Agenda Item

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Decision 89 12 057 DEC 20 1989

566 ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for authority among other things, to increase its rates and charges for electric and gas service. (Electric and Gas) (U 39 M)	Application 88-12-005 (Filed December 5, 1988)
And Related Matter.	I.89-03-033 (Filed March 22, 1989)

(See Decision 89-09-093 for appearances.)

I N D E X

INTERIM OPINION

I. Summary of Decision

This decision authorizes Pacific Gas and Electric Company (PG&E) to increase electric rates by $44,209,100 and to increase gas rates by $39,005,000 for test year 1990.

The adopted electric and gas revenue requirements represent increase of 0.75% and 1.31% respectively, over current revenue at present rates.

PG&E is further authorized to file for an attrition allowance in 1991 and 1992 in accordance with the attrition rate adjustment mechanism and the terms of this decision.

In addition, this decision reaffirms this Commission's belief that energy efficiency programs, funded by utilities, play an important role in a utility's resource plan. This decision reverses recent trends of declining investments in efficiency programs by both increasing the funds authorized for use in efficiency programs and beginning a process of reevaluating the Commission's policies on Demand-side Management (DSM) programs in general.

II. Procedural Background/Overview of the Proceeding

A. Procedural Summary

The formal process leading to this decision in PG&E's general rate case began on September 1, 1988, when PG&E filed its Notice of Intention (NOI) to seek rate increases. After PG&E resolved some 144 deficiencies, the NOI was accepted by means of a letter of the Commission's Executive Director on October 6, 1988.

On December 5, 1988, PG&E filed A.88-12-005 to increase the gross revenues from base rates in effect on October 1, 1988, by $365,009,000, or 6.7%, for the Electrical Department and $125,056,000, or 5.1%, for the gas department. The total combined increase was $490,065,000, or 6.2%. The rates reflecting the requested increased revenues are to take effect on January 1, 1990.

A prehearing conference was held on January 20, 1989, and on February 1, a ruling of the ALJs set a schedule of evidentiary hearings beginning March 8.

On March 8, PG&E revised its request in response to prepared testimony circulated by the Commission's Division of Ratepayer Advocates (DRA). The revised increase over rates subject to our jurisdiction and in effect on January 1, 1989, was $195,451,000 for the electric department and $80,161,000 for the gas department, a total of $275,612,000. The reductions from the previous request in part reflect the higher rates in effect on January 1 and a lower cost of capital than originally projected.

On March 22, we issued an Order Instituting Investigation (I.) 89-03-033 into the rates, charges, and practices of PG&E. This order serves as the procedural vehicle for considering various recommendations that may go beyond the scope of the relief requested in A.88-12-005. This investigation was consolidated with A.88-12-005.

An ALJ's ruling of April 24 consolidated the revenue allocation and rate design issues of A.89-04-001, PG&E's 1989 Energy Cost Adjustment Clause (ECAC) proceeding, with this general rate case. An ALJ's ruling of May 24 determined that the ECAC sales forecast would be used in updated testimony on revenue allocation and rate design.

An ALJ's ruling, dated April 20, 1989, referred the testimony by Utility Design Inc. (Utility Design) and the Engineers and Scientists of California (ESC) to the companion investigation, I.89-03-033. The ruling also requested briefs on legal questions relating to this testimony. Briefs were filed by Utility Design, ESC, PG&E, DRA, and Southern California Edison Company. We anticipate that a proposed decision on these legal issues will be issued in January. We also note that Utility Design has filed a recent complaint, Case (C.) 89-10-054, raising issues which are similar to those set forth in this proceeding. It may be appropriate to consolidate Utility Design's issues pending in this proceeding with C.89-10-054. We will consider consolidation after PG&E has filed an answer to the complaint.

The comparison exhibit, Exhibit 84, was filed on July 7 to show the final differences between PG&E and DRA. PG&E's final requested increase in revenues from CPUC-jurisdictional rates is $211,055,000 for the electric department and $74,756,000 for the gas department, for a total of $285,811,000. The requested increase in base revenues is $249,591,000 for the electric department and $74,756,000 for the gas department, a total of $324,347,000.

The final revenue requirement that leads to the revenue allocation, rate design, and adopted rates in this decision include the revenue requirements from several sources: the results of operations section of this decision; the ECAC proceeding, A.89-04-001; the Cost of Capital proceeding, A.89-05-019; and the proceeding on assistance for low-income customers, I.88-07-009.

The issue of the proper level of payments to qualifying facilities for avoided operations and maintenance (O&M) costs was split off from the remainder of this case by an ALJ's ruling of June 21. Opening briefs on this issue were filed on July 7 and reply briefs were submitted on July 19. This issue was resolved in Decision (D.) 89-09-093, dated September 27, 1989.

Opening briefs on all remaining issues were filed on July 26 and August 2, and reply briefs were filed on August 16. Update hearings were held during the week of September 11. Because certain issues raised during the update hearings required further argument, parties were permitted to file supplemental briefs on September 20.

On December 14, 1989, PG&E filed a petition to modify its recent ECAC forecast decision, D.89-12-015. PG&E requests the modification to reflect a reduction of the adopted ECAC revenue requirement on January 1, 1990, rates by $103,700,000 through a one-time adjustment for unbilled revenues. Although PG&E's petition is ambiguous, it should be assumed for the purposes of this decision that PG&E is actually proposing to reduce the ECAC balancing account accrual by that amount.

There was not adequate time to resolve this petition prior to the issuance of this general rate case decision. In D.89-12-015, the Commission authorized an ECAC revenue requirement of $3,225,201,000. That is the revenue requirement which must be carried forward for consolidation in the general rate case. The PG&E petition places $103,700,000 of that amount at issue. Although we are not prepared to rule on the substance of PG&E's petition, we should not put into rates an amount which may be legitimately in dispute. Therefore, for the purpose of setting January 1, 1990, rates we will include the unbilled revenues adjustment to the ECAC revenue requirement. In the context of the ECAC proceeding, we will consider the merits of PG&E's petition.

B. Public Participation Hearings

In addition to more than 60 days of evidentiary hearings held in San Francisco, public participation hearings were held in Placerville, Eureka, Red Bluff, San Jose, and Fresno. Over 75 members of the public made statements, and some of the issues raised during these hearings require further comment.

During the hearing in Placerville, petitions signed by roughly 4,000 customers expressed a concern about rising electric rates. The statements of members of the public in Placerville pointed out some particular problems with the application of baseline rates to customers living in the foothills of the Sierra Nevada. The area has cold winters, and many customers do not have gas service and are forced to heat with electricity. A combination of lower baseline allowances and rising baseline rates has hit these customers particularly hard in recent years, according to the public statements.

Some of the decisions in this case--decreasing the differential between Tier 1 and Tier 2 rates and implementing a low-income ratepayer assistance program--may help reduce the effect of the baseline system on these customers. We remain concerned, however, about the suggestion that these customers' efforts to conserve electricity have come back to haunt them in the form of reduced baseline quantities. Baseline quantities are determined from historical consumption levels for each climate zone. All-electric customers in areas with cold winters have a strong incentive to take advantage of conservation programs and equipment, and we heard repeated testimony of customers who had made tremendous efforts to reduce their consumption. If reduced consumption due to conservations results in lower baseline quantities, which in turn diminishes conservation's effect of lowering bills, it is not surprising if these customers begin to question the value and effectiveness of their conservation investments.

We will direct the Commission Advisory and Compliance Division (CACD) to investigate the extent to which conservation has led to reduced baseline quantities, particularly in the zones with harsher climates. The report of this investigation will be due on April 1, 1990, a date that will give us time to consider whether any adjustments should be made when baseline quantities are changed on May 1, 1990.

Speakers at the public participation hearing in San Jose raised several issues about the problems customers who do not speak English have in dealing with PG&E. The ALJ asked PG&E to work with the customers raising this issue to see if a bilingual person could be assigned to the office serving these customers. The ALJ also directed PG&E to consult with our Public Advisor's Office to try to develop formats for printed notices to accommodate translations or summaries in foreign languages.

PG&E serves an area where many people who do not speak English live. Many customers who speak only a foreign language tend to concentrate in specific geographical locations. As a matter of good policy and good business, PG&E should make particular efforts to assure that all customers in these areas are provided with good service that responds to any utility-related problems that may arise. An ability to communicate with customers who do not speak English is essential to serving these customers effectively.

We endorse the directions of the ALJ on these matters. PG&E reported that its labor contracts limit its ability to assign bilingual workers to particular offices. We do not seek to interfere with the terms of the contracts between PG&E and its workers, but we urge PG&E to do everything permitted by existing contracts to assign bilingual workers to offices that serve areas with a substantial population of customers who speak only a foreign language. In addition, when labor contracts come up for negotiation, PG&E should seek to obtain some flexibility in assigning bilingual workers to offices where their linguistic skills are needed. We further direct PG&E to continue to work with the Public Advisor's Office to develop notices that are meaningful to those who do not speak English.

C. Intervening Parties

The following list identifies the parties (apart from PG&E, DRA, and the parties who were concerned only with the O&M issue) who participated actively in this proceeding and the abbreviations we use to refer to them throughout this decision.

Anchor Glass Container and Energy System Engineers, Inc. (Anchor)

Association of California Water Agencies (ACWA)

California City-County Street Light Association (Cal-SLA)

California Department of General Services (DGS)

California Energy Commission (CEC)

California Farm Bureau Federation (CFBF)

California Large Energy Consumers Association (CLECA)

California League of Food Processors (the League)

California Manufacturers Association (CMA)

California-Nevada Community Action Association (Cal-Neva)

California Travel Parks Association (CTPA)

Cogeneration Service Bureau (CSB)

Contra Costa County (Contra Costa)

Energy and Resources Advocates (ERA)

Engineers and Scientists of California (ESC)

Federal Executive Agencies (FEA)

Industrial Users (Industrial Users)

Local 1245, International Brotherhood of Electrical Workers, et al. (LIBEW) Unions

Power Users Protection Council (PUPC)

San Diego Gas & Electric Company (SDG&E)

Schools Committee to Reduce Utility Bills (SCRUB)

Southern California Edison Company (Edison)

Southern California Gas Company (SoCalGas)

Tecogen, Inc., Milpitas Unified School District, and other members of the Small Cogenerators of California (SCC)

Toward Utility Rate Normalization (TURN)

Unocal Corporation (Unocal)

Utility Design, Inc. (Utility Design)

Western Mobilehome Association (WMA)

III. <u>Results of Operation</u>

This decision determines the revenue required by PG&E in 1990 to provide safe and reliable service at the lowest reasonable cost. The challenges posed in this proceeding were well explained in D.85-03-042:

> "Ratemaking is not, nor has it ever been, an exact science that guarantees perfect results from all perspectives. Ratemaking, whether in a general rate proceeding or by an attrition mechanism, is essentially the art of estimating future events based on judgment that is as fully informed as possible. We know in prospective test year ratemaking that our adopted estimates of revenues and expenses may be at variance with actual hindsight experience. But we do not view this as a problem, because we are extending to utility

> management an opportunity and incentive to find ways to conduct operations for less than projected. When it can do this it flows the benefit to the utility's bottom line, which means profit. In the short term, between general rate proceedings, the shareholders benefit when the company's management can 'do it for less,' and correspondingly, ratepayers ultimately benefit because the productivity improvement will be reflected periodically when there is a comprehensive review of the utility's revenue requirement... Accordingly, we are not as concerned as some parties are about having ratemaking that is always perfect from the hindsight perspective. Rather, we will continue our practice of adopting sound, informed estimates with the hope that utility management accepts the challenge and can somehow 'do it for less.'" (D.85-03-042, mimeo. p. 6.)

To assist the Commission in developing a sound and informed estimate, PG&E and DRA began by examining the last "test year," 1987. This is the most recent period for which complete financial data is available. DRA has carefully examined the company's books for this period to determine, among other matters, whether the recorded expenses were actually incurred, whether the expenses were a necessary cost of service and whether the amount of the expenditures was reasonable.

PG&E and DRA have used the 1987 test year, or an alternative period, as a basis for estimating the future revenue requirements in 1990. The base period used for the estimate is adjusted for specific factors which occurred in the past test year or are expected to occur in the future test year. In addition, most base period estimates are adjusted for inflation which is reasonably expected to occur between the last test year (1987) and the next test year (1990).

We will first address PG&E's projected revenues. Second, we will review the results of operations for the electric department for test year 1990. There are a number of issues which are common to the electric and gas departments. Where such common issues arise they will be addressed under the electric department. Third, we will address the expenses which are unique to the gas department. Finally, we will address several issues which relate to general operations. Except as expressly noted, where there is agreement among the parties, we will adopt PG&E's estimate. Therefore, the decision will focus primarily on the areas of disagreement between the parties.

A. Revenues

1. Sales Forecasts

PG&E's revenue allocation exhibit proposed use of the sales forecast developed in the ECAC for purposes of revenue allocation and rate design. ALJ Cragg's Ruling of May 24, 1989 concluded that the ECAC sales forecast figure, issued in mid-August in ALJ Weissman's decision on resource assumptions in the PG&E ECAC proceeding (A.89-04-001), should be used as the sales forecast in the general rate case proceeding to develop updated testimony on revenue allocation and rate design.

In accordance with ALJ Cragg's Ruling, the final revenue allocation and rate design in this proceeding is based upon the adopted sales forecast issued by ALJ Weissman in his Ruling of July 28, 1989 in A.89-04-001. These figures were incorporated in the update testimony submitted by DRA and PG&E on August 28, 1989.

2. Other Operating Revenues

Other operating revenues are revenues obtained by a utility from other than the sale of electricity or gas.

PG&E is forecasting 1990 test year Other Operating Revenue of $41,931,000 for the CPUC jurisdiction. DRA's forecast is $4,463,000 higher. The differences occur in three revenue accounts.

a. Account 370

PG&E forecasts a net expense of $18,000 for Revenue Account 370, Miscellaneous Service Revenue. PG&E's revenue estimate is based on a "moving average" of 60 months of recorded revenues between 1983 and 1987. PG&E characterizes the revenue stream in this account as volatile, with no apparent trend or pattern.

DRA forecasts positive income in Account 370 of $1,174,000. DRA's revenue estimate is based on an average of recorded revenues between January 1987 through September 1988. DRA believes it detects a reversal of the historic trend of negative revenues for this account.

Neither PG&E's nor DRA's estimate is entirely satisfactory. While DRA's estimate is more current, it is based on only 21 months of data. In contrast, most expense forecasts by DRA and PG&E which rely on averages incorporate three or four years of data. While PG&E's forecast relies on a longer estimating period, PG&E has not justified using as much as five years of data, including data from as far back as 1983.

When faced with choosing between a more current forecast period and a longer, but older forecast period, we believe that the current forecast period is a more accurate forecast of anticipated revenue. We adopt DRA's forecast of $1,174,000 for Revenue Account 370.

b. <u>Account 371</u>

PG&E and DRA used identical methods of forecasting revenue in Revenue Account 371, Sales of Water and Water Power. However, since DRA's forecast was prepared after PG&E's, DRA was able to use an updated estimate of 1988 revenue. PG&E agrees to DRA's updated revenue forecast of $361,000.

c. <u>Account 372</u>

PG&E forecasts $14,050,000 in revenue for Revenue Account 372, Rent From Electric Properties. PG&E bases its forecast on a three-year average for the 1985-1987 period.

DRA forecasts revenue of $16,627,000 for Revenue Account 372, using the same three-year period as PG&E. DRA's estimate is higher because DRA also escalates 1985-87 revenues by the Materials and Service Index (MSI).

PG&E believes that there is no evidence to support the use of the MSI to escalate the 1985-87 revenue estimate. However, PG&E did not directly confront DRA's proposition that nominal rent revenues are influenced by inflation, and are reasonably expected to grow at the rate of inflation. PG&E states, in its Opening Brief, that DRA's escalating factor "ignores the trend in the recorded data," but PG&E does not explain what this trend has been. In the absence of more specific data on the trend in Account 372, we believe it is reasonable to expect an increase in the account between 1987 and 1990 at the rate of inflation. Since the accounts covering rents paid by PG&E are escalated by the MSI index, it is reasonable to escalate similarly the rents received by PG&E. Therefore, we will adopt DRA's forecast of $16,627,000.

B. Escalation

PG&E and DRA are in agreement regarding the methodology to be used in developing labor and nonlabor escalation rates for the test year.

For the labor escalation rate, PG&E proposes to escalate labor costs by the terms of the general wage increase in the current collective bargaining agreement (2.75%) in 1988 and 1989, and to use the percentage change in the consumer price index in the attrition years thereafter. We will adopt the agreed-upon labor escalation rate of 2.75% in 1988 and 1989, and 4.9% in 1990.

For the non-labor escalation rates, PG&E proposes to use the Materials and Service Index (MSI), as we did in the 1987 general rate case (D.86-12-095), with a slight modification to reduce complications in calculating the detailed cost elements. Applying the agreed-upon methodology, we adopt non-labor escalation rates of 5.17% in 1988, 4.6% in 1989, and 4.83% in 1990.

C. Electric Department Expenses

Both PG&E and DRA have prepared complete estimates of PG&E's results of operation in 1990. Table 1 presents a comparison of PG&E's and DRA's estimate of electric department results of operation for the test year, as well as the revenue and expense estimates which we adopt in this decision. The electric department is divided into four areas of operation, and each area of operation is divided into individual accounts. Within each account, there is a labor component and a materials and services (M&S) component. For many accounts, no party disputes PG&E's estimate of test year expenses.

1. Production Expenses

Production expenses are all costs, excluding fuel, associated with generating electricity. These costs include the costs of operating and maintaining PG&E's electric generating facilities.

PG&E requests $119,468,000 in electric department Production Maintenance expenses and $91,319,000 in Production Operating expenses. DRA recommends that PG&E's request be reduced by $2,551,000.

The differences in Accounts 514, 524, and 545.5 are discussed in Section III.E of this decision.

The differences in the other accounts result from differences in estimating methodology. The parties in this proceeding have used different procedures to forecast the reasonable cost to PG&E of providing and maintaining a reasonable level of service in 1990. Three PG&E witnesses, Plachta, Fowler, and Tatarian, testified regarding PG&E's forecasting methodologies. They testified that PG&E's forecast for each account represents the expected level of work or activity in that account in the test year. For each account, PG&E began with a base estimate, and then adjusted the base estimate to reflect changes in the account activity expected in the test year. In almost every case, PG&E

TABLE - 1

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
SUMMARY OF EARNINGS AT PRESENT RATE
REVENUES AND EXPENSES
(Thousands Of 1990 Dollars Unless Otherwise Indicated)

Description	PG&E	DRA	ADOPTED
Operating Revenues	$3,148,146	$3,167,409	$3,140,921
Operating Expenses			
Production	210,787	202,270	207,622
Transmission	56,241	53,835	53,942
Distribution	278,206	271,910	272,994
Customer Accounts	96,971	95,668	96,971
Uncollectibles	6,973	7,016	6,957
Demand-Side Management	86,288	98,438	99,953
Administrative & Heneral	411,595	332,221	365,917
Franchise Requirements	19,558	19,682	19,513
Other Adjustments	(2,994)	(45,864)	(16,159)
Subtotal (1987 Dollars)	$1,163,625	$1,035,176	$1,107,710
Labor Escalation Amount	59,841	50,010	55,925
Non-Labor Escalation Amount	62,970	59,601	59,658
Subtotal (1990 Dollars)	$1,286,436	$1,144,787	$1,223,293
Energy Cost	2,651	2,651	2,651
Project Amortization	3,968	3,968	24
Depreciation	525,598	519,580	524,038
Nuclear Decommissioning Exp.	75,050	67,819	75,048
Taxes Other Than On Income	147,254	139,918	144,418
Superfund tax	1,095	1,095	1,074
CA Corporation Franchise Tax	75,419	92,409	81,215
Federal Income Tax	274,239	330,385	293,420
Total Operating Expenses	$2,391,710	$2,302,612	$2,345,181
Net Operating Income	$756,436	$864,797	$795,740
Rate Base	$7,989,909	$7,886,868	$7,937,157

used as its base estimate either the actual recorded expenses for 1987, a four-year average of expenses (1983-1987), or a four-year trend.

Generally, PG&E relied upon 1987 recorded expenses for its base estimate. However, for those accounts which may be influenced by outside forces, such as weather, third-party activities or relatively random events, PG&E used a four-year average.

As Tatarian explained:

> "Accounts with outside influences, there are some accounts that are heavily influenced by weather patterns, by third-party activities, relatively random events. Those it was determined for the most part -- you can't predict the actual level -- it's subject to forces of nature in some cases.
>
> "So on those it was very clear that a four-year average or some average of some kind was appropriate because it's not something that is trendable or predictable...."
>
> "In cases where there appeared to be anomalies and they appeared to be valid expenditures, that is another where I would tend to average it because I couldn't explain why there was so much extra activity in this one account four or five years ago, and I had to assume it was valid at the time, and it was a cyclical account that may repeat that in the future, so averaging seemed reasonable." (Tr. 3:235-236.)

DRA generally derived the base 1990 estimate using either 1987 recorded expenses, or an average of two, three or four years:

> "Now for 1987 recorded, I would use -- the expense represents a normal, or a stable level of activity and few external influences, for example not storm-related, and a second is where the expenses have had a constant decline.
>
> "The average I used is four years where the expenses were cyclic or fluctuating, or when there was a large increase or decrease in 1987, and in some instances I used a three-year

> average where recent expenses were close, and again in some instances I used a two-year average where 1986 and 1987 were close, but with a small increase or decrease in '87." (Tr. 9:866.)

From these descriptions of the parties' methodologies, we may discern general agreement on certain principles for developing a base estimate of 1990 expenses:

1. If recorded expenses in an account have been relatively stable for three or more years, the 1987 recorded expenses is an appropriate base estimate for 1990.

2. If recorded expenses in an account have shown a trend in a certain direction over three or more years, the 1987 level is the most recent point in the trend and is an appropriate base estimate for 1990.[1]

3. For those accounts which have significant fluctuations in recorded expenses from year to year, or which are influenced by weather or other external forces beyond the control of the utility, an average of recorded expenses over a period of time (typically four years) is a reasonable base expense for 1990.

Once a base 1990 estimate is established, both PG&E and DRA determine whether there are specific changes in the level of expenses in a particular account, which are known or reasonably expected to occur in 1990. If so, the base estimate is adjusted to account for these anticipated changes.

With these principles in mind, we will now examine the parties' forecast of production expenses.

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1 If there is an established trend and if the trend is expected to continue, FEA believes that we should project the trend to 1990, and further increase or decrease the forecast of expenses in the account. See Section III.C.3.a, infra.

a. Account 500: Supervision and Engineering

DRA's base estimate of the Materials and Service (M&S) component of this account is $62,000 lower than PG&E's estimate.

The expenses in the M&S component of this account have declined steadily over the past four years. Because of this steady decline, and because 1986 and 1987 expenses are fairly close, DRA based its estimate on the 1987 recorded expenses.

PG&E used a four-year average to establish the base estimate for the M&S component of this account. PG&E does not explain in its direct testimony why it used a four-year average. In its opening brief, PG&E explains that an average was used because "PG&E has found that expenses are sometimes cyclic (PG&E, Fowler, Tr. 866)."

While it is true, speaking generally, that expenses in some accounts are sometimes cyclic, the PG&E witness did not testify that the expenses in Account 500 are cyclic, nor is there any indication of cyclic activity in recorded expenses since 1984. The trend is clearly downward, not cyclic.

We will adopt DRA's estimate for the M&S component of Account 500.

b. Account 506: Miscellaneous Steam Power Expenses

DRA's base estimate of the M&S component of this account is $123,000 lower than PG&E's estimate.

DRA used 1987 recorded expenses as the base estimate because the expenses in this account have declined steadily between 1985 and 1987.

PG&E's opening brief states that it used a four-year average because the "1987 amount did not represent the level of activity for materials and services [in 1990]." However, PG&E has not explained, in either its testimony or its briefs, why it believes that 1987 recorded M&S expenses would not be representative of 1990 expenses.

PG&E's reply brief seeks to support its position on M&S expenses in this account by citing Plachta's explanation that "the 1986 amount was abnormally high (Tr. 341)." However, Plachta was describing here the labor component of the account, not M&S. There is no disagreement between DRA and PG&E on the labor component of Account 506.

We will adopt DRA's estimate of the M&S component of Account 506.

c. Account 512.2: Boilers and Related Apparatus

As with Account 506, the recorded expenses in the M&S component of Account 512.2 have declined steadily between 1985 and 1987. Because of this decline, DRA used 1987 recorded expenses for its base estimate. PG&E used a four-year average "just to levelize the account." (Tr. 4:345.) PG&E's Plachta testified that the downward trend in this account "appears to be a cyclic curve which reached its high point [in 1985] and then takes a number of years to reach a low point again." (Id.) Plachta did not explain when he anticipated the cycle to reach its low point. In the absence of such information, the 1987 recorded expenses represent a reasonable midpoint between a possibility that the cycle in expenses may continue to decrease or may begin to increase by 1990. We will adopt DRA's estimate.

d. Account 512.3: Boiler Plant Auxiliaries

This is another account in which one component of the cost, in this case labor, has trended downward in each year between 1985 and 1987. Because of the downward trend, DRA used 1987 recorded expenses to establish a base 1990 estimate of the labor component.

PG&E used a four-year average for its base estimate because Plachta did not see any fluctuation in the account, or because the fluctuations, in terms of percentage, were very small. In this instance, the "fluctuation" was a three-year downward trend in expenses. Accordingly, we adopt DRA's estimate of the labor component of Account 512.3, which is $593,000 lower than PG&E's estimate.

e. Account 513.5: Main Turbogenerator Auxiliaries

The expenses in the labor component of this account have fluctuated between 1984 and 1987, with no discernible trend. DRA used a four-year average to establish a base 1990 estimate. PG&E used 1987 recorded expenses. PG&E notes that DRA consistently used the 1987 recorded figures for accounts which have been declining. "Therefore, to be consistent with its reasoning," PG&E argues, "the DRA should use the 1987 value when the account is steadily increasing."

We agree with PG&E that it is important to be consistent in applying forecasting methodologies. However, we do not agree that the expenses in this account have been "steadily increasing." In other instances where we have adopted a 1987 value for the base estimate, we have observed a trend in expense levels of three years or more. In contrast, the labor expenses in Account 513.5 have fluctuated yearly. Costs have increased, but not steadily.[2]

We are not persuaded by PG&E's rationale for choosing to use 1987 recorded expenses, rather than a four-year average ("...I saw no great difference in percentage and I used the last recorded year)." (Tr. 4:348.) We find more persuasive Plachta's additional explanation that advanced aging of steam plant equipment as a result of cycling duty may tend to increase maintenance costs for smaller equipment requiring additional care. Unfortunately, the witness did not make a specific aging adjustment for this account,

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2 The recorded expense levels of the labor component of this account between 1984 and 1987 are:

1984:	$5,576,000
1985:	$6,148,000
1986:	$5,753,000
1987:	$6,326,000

as he did for other accounts.[3] In the absence of specific evidence regarding the added costs of this increased maintenance, we believe that an amount slightly above the four-year average of the labor expense will best represent expected costs in 1990. We will increase 1987 recorded expenses by $100,000.

f. <u>Account 546: Supervision and Engineering</u>

Expenses in the M&S component of this account have been stable between 1985 and 1987. Due to this stability, DRA chose 1987 recorded expenses for its base estimate of M&S expenses. PG&E chose to use a four-year average, resulting in an estimate $1,000 higher than DRA. We find that DRA's estimate is more reflective of expected activity in a very stable account for 1990. We adopt DRA's estimate.

g. <u>Account 548: Generation Expenses</u>

The M&S component has fluctuated significantly over the past four years, with no discernible trend. This is precisely the circumstance in which it is appropriate to use a four-year average to establish the base 1990 estimate. PG&E properly used a four-year average. Moreover, here PG&E specifically offered evidence that M&S expenses in this account tend to be cyclic.

Under DRA's announced forecasting criteria, DRA should not have used 1987 recorded expenses where the account was cyclic and exhibited "extreme fluctuations." We will adopt PG&E's estimate for the M&S component of Account 548.

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3 PG&E's reply brief characterizes the difference in forecasting a base estimate as "an adjustment of $376,000 for increased maintenance due to cycling duty," but the record does not indicate that PG&E ever determined a specific value for such an adjustment.

h. **Account 514: Miscellaneous Steam Plant,**
Account 524: Miscellaneous Nuclear Plant,
Account 545.5: Miscellaneous Hydraulic Plant

DRA believes that PG&E estimates of miscellaneous expenses for these three accounts are reasonable, except for one item. DRA proposes reducing these accounts reflect the transfer of hazardous waste funds which DRA believes were "overlooked" by PG&E. PG&E denies that it overlooked these transfers. PG&E states that these adjustments are not related to the account and not established by a DRA witness. We agree with PG&E that the necessity for DRA's proposed adjustment has not been adequately explained. We reject DRA's proposed adjustment.

2. Transmission Expenses

Electric transmission expenses are those incurred by the utility to operate and maintain substation structures, equipment, and protective devices, overhead circuits consisting of poles, towers, insulators, conductors, and line equipment, underground circuits consisting of duct, conductors, enclosures, and line equipment, roads, rights-of-way, and miscellaneous plant operated at voltages of 50 kV and above. Expenses include labor, material, supplies, contracts, and other related expenses of operating and maintaining the transmission system.

a. Account 560: Operation, Supervision, and Engineering

PG&E's estimate of the base 1990 expense for the labor component of this account exceeds DRA by $42,000. PG&E based its estimate upon the 1987 recorded expenses; DRA used an average of three years (1985-1987). As in the case of many accounts, the difference in estimates between DRA and PG&E is very slight. Where 1987 expenses are approximately equal to an average of several years, it is reasonable to use 1987 data as the base. We adopt PG&E's estimate of the labor component.

b. Account 563: Overhead Line Expenses

DRA concurs with PG&E's labor and M&S accounts, except for PG&E's proposed adjustment of $513,000 for increased patrols caused by growth, increased utilization, and storm damage. D.86-12-095 authorized $1,143,000 to increase and improve line patrols and $623,000 for improving the service reliability program which contained funds for additional programs. DRA believes that these additional funds are sufficient, and that no further increases have been justified.

In response, PG&E states that the additional funds are necessary to increase patrols to what PG&E believes is the appropriate level. PG&E cites its response to a DRA data request as providing the information "to support the need for the additional funding." If PG&E had provided the record with this information, we would have examined this evidence and may have concluded that a further increase in funding for patrols is warranted. Unfortunately, PG&E chose not to put this response into evidence.[4] We agree with DRA that PG&E has failed to demonstrate the necessity for an a further increase in funding for line patrols in 1990. We adopt DRA's adjustment of $513,000.

c. Account 566: Miscellaneous Transmission Expenses

PG&E proposed adding $575,000 for 500 kV bare hand live-line training in 1990. DRA agrees that this new maintenance technique is beneficial, but DRA questions the timing of the program. DRA states that PG&E must obtain approval from Cal-OSHA before this technique can be used. DRA is opposed to the increase because approval has not been obtained and, in DRA's opinion, may

4 We remind PG&E that its burden of proof is not satisfied merely by responding to DRA's data request. DRA does not determine the reasonableness of rates. This Commission does. We can do so only if the information is made available on the record.

not be obtained in the near future. PG&E's witness testified that PG&E expects Cal-OSHA approval by the end of 1989 or early 1990.

In its reply brief, PG&E agrees that the estimate for this program could be reduced by approximately 30% ($114,000 for labor and $55,000 for M&S) "to reflect somewhat slower development and changed scope for the program." The reference to slower development apparently refers to delays in obtaining Cal-OSHA or union approval. PG&E does not explain what it means by the "changed scope" of the program.

We believe that the bare hand live-line training is a beneficial program. We will approve PG&E's reduced estimate of the costs of this training program. We also direct PG&E to report fully in its next GRC application on the costs and benefits of this new program in 1990 and 1991.

d. <u>Account 568: Maintenance, Supervision, and Engineering</u>

The M&S component of this account increased each year between 1984 and 1986, and decreased in 1987. PG&E derived its base estimate from 1987 recorded expenses. DRA used a four-year average. We find that PG&E's estimate is most representative of costs in this account in 1990.

e. <u>Accounts 562 and 570</u>

DRA removed substation expenses from Accounts 562 and 570 that it believes are associated with Diablo Canyon. PG&E's brief did not contest this adjustment. We adopt DRA's adjustment.

f. <u>Account 571.63: Replacement Line Insulators</u>

The recorded labor expenses in this account have fluctuated significantly between 1984 and 1987, with no discernible trend. PG&E used 1987 expenses for its base 1990 estimate. DRA based its estimate on a four-year average, resulting in an estimate $113,000 lower than PG&E's estimate.

Given that the 1987 expenses are approximately 50% higher than expenses in 1986 or 1988, we do not find the 1987 expenses to be an accurate reflection of anticipated base workload in 1990. Instead, we will adopt DRA's estimate.

g. Account 571.65: Moving and Relocating Poles and Guys

PG&E's estimate for the labor component (using 1987 expenses) exceeds DRA estimate (using a three-year average, 1985-87) by $7,005. We adopt PG&E's estimate for the same reasons as stated under Account 560.

h. Account 571.66: Pole Treating

PG&E requests an increase in the M&S component of this account of $99,000 for increased testing and treating of wood poles, for a total of $136,000 in 1990. DRA notes that in D.86-12-095, PG&E requested and received an increase of $41,000, up to a total of $162,000 (in dollars) for testing of poles in 1987. Yet, in 1987 PG&E incurred only $37,000 for transmission pole treating. In 1987 the company tested only 54,000 poles, significantly short of its goal of 133,000 poles per year. Thus, for 1990 PG&E adjusted the 1987 recorded expense level to provide for the anticipated optimum level, plus additional funds to amortize the 1987 shortfall over a three-year period.

As PG&E was previously authorized sufficient funds to test 133,000 distribution poles per year in 1987 through 1989, we will not authorize additional funds for PG&E to test the previously funded "shortfall." It will be PG&E's responsibility to make up this shortfall with funds previously provided by ratepayers for that purpose.

We will authorize a total of $90,000 in Account 571.66.

i. Account 571.68: Reconditioning Conductors

PG&E used a four-year average to estimate the M&S component of this account. DRA used 1987 recorded expenses. The M&S component of this account has declined in each year between 1985 and 1987. Therefore, we will adopt DRA's estimate of M&S expenses which is based on 1987 recorded expenses. As we have explained previously, if an account shows a discernible trend over three or more years, an estimate based on a four-year average does not adequately account for the trend.

PG&E used a four-year average to estimate the labor component of this account. DRA used a two-year estimate for reasons that are not well explained. We will adopt PG&E's estimate of the labor component of Account 571.68.

j. <u>Account 571.71: Painting Poles, etc.</u>

PG&E used a four-year average for the labor and M&S components of this account. DRA relied upon 1987 recorded data due to the "unpredictable pattern of 1984 and 1985 expenses." Yet, according to DRA's explanation of forecasting methodology, when expenses fluctuate with no apparent trend, a four-year average should be used. We will adopt PG&E's estimates for this account.

k. <u>Account 571.72: Other Overhead Line Maintenance</u>

Here again, PG&E used a four-year average to develop a base estimate of the labor and M&S components of this account. For the labor component, DRA based its estimate on the 1987 recorded expenses, because the recorded expenses have shown a three-year decline from 1985 to 1987. In recognition of this trend, we adopt DRA's estimate of the labor expenses.

For M&S expenses, DRA used the 1987 figure because the expense levels for prior levels were unstable. As we have stated previously, this is precisely the circumstance in which a four-year average should be used. We will adopt PG&E's base estimate for the M&S component of this account.

DRA also opposes PG&E's request for an increase of $170,000. PG&E identifies this item as needed "for increased roadwork to support new equipment," but with no further explanation. DRA believes this expense is unnecessary in light of previous funds received by PG&E for this purpose. PG&E attempts to further explain the purpose of the requested increase in its opening brief, without citation to the record. We cannot accept

PG&E's argument in place of evidence. We decline to adopt this adjustment.

l. <u>Account 571.74: Vegetation Control</u>

To estimate the labor component of this account, PG&E used 1987 recorded expenses. DRA used a four-year average in order to "smooth out annual fluctuations." In this instance, there is a three-year trend in increasing labor costs. We will therefore adopt PG&E's estimate.

m. <u>Account 571.75: Right-of-Way-Clearing</u>

As with other instances where PG&E estimates 1990 expenses using 1987 data and DRA uses a two-year average, we prefer to use 1987 data. We will adopt PG&E's estimate for M&S in this account.

n. <u>The High Voltage Direct Current Expansion Project</u>

In Exhibit 61 PG&E proposed that the estimated electric transmission expenses forecast under Account 565 be increased by $4,508,000 per year beginning in 1990 and continuing at this level through attrition years 1991 and 1992. DRA and PG&E had entered into a stipulated agreement (Exhibit 62) regarding rate treatment for this project. In PG&E's update exhibit, PG&E and DRA revise the stipulated amount to $3,900,000, a reduction of $608,000 from the original request.

The purpose of the requested increase is to cover the costs of PG&E's participation in the Pacific Intertie High Voltage Direct Current (HVDC) Expansion Project. The project, as described by PG&E, involves the expansion of the alternating current to direct current converter facilities for the Pacific Intertie HVDC Transmission line located at Sylmar Substation in Los Angeles, and related work to increase the nominal transfer capacity from approximately 2,000 MW to 3,100 MW. These facilities are financed and owned by LADWP, Edison, and the cities of Glendale, Burbank, and Pasadena. The converter facilities were declared operable by LADWP on April 25, 1989.

PG&E is negotiating with Edison for a share of the project. As of the close of the record, PG&E had not concluded negotiations. PG&E is hopeful that the negotiations will lead to PG&E's participation in the project. If expenses are lower under the final arrangement, PG&E will notify the Commission. PG&E asks that the expenses be reviewed now in anticipation of a favorable outcome of negotiations.

PG&E expects to receive 275 MW of additional transmission capacity. The nominal scheduling entitlement at the Nevada-Oregon border will be approximately 258 MW. Of this, PG&E plans to lay off 25 MW to the City of Santa Clara, for the period 1990 through 1996 at $24/kW, plus O&M costs. PG&E proposes to lay off its remaining share of the project to Edison through 1993 or later. PG&E believes that the project is beneficial to PG&E's ratepayers today (based on net present value) but the economics improve the longer it can delay its participation.

The HVDC expansion project was a major issue in Edison's last general rate case. In D.87-12-066 we established a cost cap of $80 million for Edison's share of the HVDC expansion project, and we authorized Edison to file for an increase in the MAAC rate, subject to refund, equal to 75% of the annualized investment related revenue requirement for the HVDC expansion after the project becomes commercially operational.[5] We further held that Edison should file an application to determine the reasonable and prudent costs of this project, not later than six months after the final portion of the project is placed in service. We placed

5 By Application 89-10-001, Edison filed its request for authority to transfer the costs for this project to base rates. According to Edison, the project met the in-service criteria on April 3, 1989. As stated in the Application, Edison's construction expenditures as of September 30, 1989 were $72,600,000, with forecasted total cost at completion of the project estimated to be $78,700,000.

Edison on notice that we intended to give further consideration to the cost-effectiveness of the HVDC expansion project in conjunction with Edison's other transmission projects and agreements with LADWP. "Edison should be made aware that the amount of investment ultimately found to be reasonable may not exceed the amount of investment determined to be cost-effective in the context of the Devers-Palo Verde proceeding." (D.87-12-066, mimeo. p. 78.)

In D.89-01-039 we stated:

> "The cost cap adopted in D.87-12-066 is exactly that: a cap on the investment that Edison will be allowed to recover in rates. To the extent that agreements with Los Angeles Department of Water and Power (LADWP) and others impact the cost-effectiveness analysis adopted in D.87-12-066 we will only consider downward adjustments to the adopted cost cap of $80 million." (D.89-01-039, mimeo. pp. 5-6.)

By the stipulation, PG&E and DRA agree that PG&E ratepayers are likely to receive net present value benefits which exceed the net present value of costs PG&E is likely to incur. Despite the agreement between DRA and PG&E that the project is likely to be cost-effective, we believe that such a conclusion is premature. The actual costs which Edison will be allowed to recover for its share of the project have yet to be determined. Until these costs are determined, it is difficult for us to conclude that PG&E's share of the project is reasonable or cost-effective. In particular, we are concerned that PG&E's payments for 50% of Edison's share of the project might exceed 50% of the costs which Edison is ultimately authorized to recover.

We are also concerned that PG&E has not reached final agreement with Edison. The actual benefits will depend upon whether PG&E obtains an agreement with Edison, when the agreement is effective, and upon the costs and terms specified in the final agreement. Given the fact that PG&E has not consummated an agreement with Edison as of the date of the proposed decision, just one month before the beginning of the test year, we find that the projected costs of this project are too speculative to be included in the test year on a forecast basis. Moreover, since Edison's costs are to be included in rates only after the project is commercially operational and subject to refund pending a reasonableness review, we believe PG&E's share of the costs should also be subject to refund.

Although, we do not adopt the stipulation, we will increase Account 565 by $3,900,000 for the estimated costs of PG&E's share of HVDC expansion project. This amount will be subject to refund depending upon the final terms of PG&E's contract with Edison and the outcome of A.89-10-001.

3. Distribution Expenses

Electric distribution expenses are those incurred by the utility to operate and maintain distribution substations, overhead and underground distribution lines, meters, services, and street lighting systems. Expenses include labor, material, supplies, contracts, and other related expenses of operating and maintaining the distribution system.

a. Various Accounts

PG&E and DRA disagree regarding electric distribution expenses in eight accounts. For two of the accounts, Account 595 (labor) and Account 596 (M&S and labor), recorded expenses have trended upward for the past three or more years (1985-87). Given these trends, we agree with PG&E that 1987 recorded expense is the most accurate prediction of anticipated workload in 1990.

The labor and M&S components of five accounts, Accounts 583.2 (M&S and labor), 588 (M&S), 593.68 (M&S), 593.73 (M&S), and 594 (labor) have fluctuated significantly over the past four years (1985-87), with no discernible trend. PG&E charges that DRA arbitrarily chose to use either 1987 data or an average, depending on which result yielded a lesser amount of money, independent of the amount of work to be performed. On the other hand, PG&E's choice yielded the higher result in each of these cases.

PG&E did not offer any explanation for its choice of 1987 data or an average in its written testimony, Exhibit 102. Under cross-examination, PG&E witness Tatarian offered explanation for some of his choices. We reviewed these explanations and do not find them persuasive. For example, he explained his rationale for using a 1987 recorded data, rather than a four-year average, as the base estimate of M&S expenses in Account 588 as follows:

> "In this particular account, again, the 1987 level was significantly below the 1986 level and somewhat higher than 1985, and given that '87 was lower, that seems to accurately reflect the amount of activity that we see in that account.
>
> "I didn't want to use the average there because of the high in '86 and the low in '85. I thought '87 seems to be accurate here." (Tr. 3:193.)

What is lacking in this explanation is why 87 "seems to be accurate," and why a four-year average of an account with significant year-to-year fluctuations would yield a less accurate estimate.

Absent a specific explanation of why 1987 recorded data best reflects the estimated 1990 expenses of an account with fluctuating expense levels and no discernible trends, we find it most appropriate to use a four-year average as the base 1990 estimate. Therefore, we will adopt an estimate based on a four-year average, for the disputed components of the five accounts listed above.[6]

For Accounts 580 and 590, both DRA and PG&E have utilized the 1987 recorded expense as the basis for the test year expense. FEA notes that both accounts have been decreasing. FEA recommends that we recognize this trend and further reduce Account 580 by $1.4 million, and reduce Account 590 by $663,000. PG&E acknowledges the trend, but argues that further reductions are speculative and imprudent. While we may generally expect improved productivity (see Section III.F), we agree with PG&E that no further decrease in these specific accounts is warranted at this time.

FEA also objects to an adjustment by PG&E and DRA to Accounts 582 and 583.30. DRA and PG&E have determined the 1990 expense by increasing 1987 recorded expenses by a factor to reflect system growth. FEA argues that there is no correlation between expenses in these accounts and overall system growth. Here we agree with FEA. If we had applied such an adjustment in the 1987 test year, assuming such a correlation, we would have overfunded these accounts. The labor component has steadily declined over the past four years. While we will not project further declines in the test year, neither PG&E nor DRA has explained why the 1987 recorded estimate should be adjusted upward.

DRA and FEA also take exception to specific adjustments in three accounts. We will discuss those next.

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6 The adjustments to the accounts 582.0, 583.3, 592.0, 908.0, 916.0, 920.0, 921.0, 922.0, 926.0, 928.0, and 930.2 were broken down into the sub-categories of labor, non-labor, and other by multiplying the total expense adjustment by factors specific to each expense and sub-category. The factors are ratios which were developed from expenses in the comparison exhibit by dividing the sub-category expenses into the total expense.

b. Account 583.2: Overhead Line Expenses

DRA opposes PG&E's requested adjustment for additional line patrols, for the same reasons stated for Account 563. As we discuss above, we agree with DRA that PG&E has failed to demonstrate on this record the need for additional line patrols in 1990.

PG&E's briefs raise additional arguments in support of this expenditure which were not made on the record. PG&E's opening brief, referring to its workpapers, states that these additional funds are for infrared patrols, over and above traditional line patrols. At this stage of the case, without the workpapers in evidence, we have no ability to determine the relationship of this expense to previous increases. PG&E's reply brief further argues, without citation to the record, that increased patrolling will help limit PG&E's liability to third party claims, with consequent savings to ratepayers. However, PG&E did not provide this analysis on the record. We would welcome such an analysis in the next general rate case.

As a result of adopting DRA's position on the base estimate and the line patrol adjustment, we reduce PG&E's overall request for this account by $403,000.

c. Account 588: Miscellaneous Distribution Expenses

DRA opposes an increase in funding for the 12/21 kV rubber glove school, for the same reasons it opposed the adjustment in Account 563. PG&E's reply brief acknowledges that there may be a question regarding a slower pace of development for the rubber glove program, indicates that it would accept a reduced estimate, based on a three-year program, to $958,000. As we explain above, we adopt PG&E's reduced estimate.

PG&E's update exhibit requests an increase of $1,159,000 in electric account 588 and $479,000 in gas account 380, to cover the costs of new safety requirements imposed by the California Motor Vehicle Act of 1988. This Act was signed into law in 1988, and took effect on July 1, 1989. PG&E states that this act will increase the costs that PG&E must bear in maintaining its fleet of vehicles. PG&E cites three new requirements:

1. A mandatory daily inspection and record of regulated vehicles.

Under cross-examination, PG&E witness Tatarian admitted that the requirement of a daily inspection was not a change mandated by the 1988 Act. Instead, the requirement for a more specific check-off system has evolved from discussions between PG&E's fleet managers and the Highway Patrol. "So while it is not directly a result of this legislation, the change is hitting us in the same cycle now...its an extra burden they have to do every day." (Tr. 64:6884.) While the change in daily inspections may be an extra burden to PG&E and may impose an extra cost (matters which DRA would dispute), the expense is not properly a subject of an update exhibit. It is not a change in governmental action such as a change in postage rates, instead "the Highway Patrol tells us that it's something that should always have been occurring under the existing statute prior to the change." (Tr. 64:6885.) As to the daily inspections, Tatarian testified generally that the required inspections will require more detail and more paperwork, but he believes that PG&E's current inspection programs adequately covered these items. (Tr. 64:6897-6900.)

2. A mandatory 45-day inspection and record of regulated vehicles.

Tatarian testified that PG&E already has "a relatively safe level of fleet operations," but because of the necessity for a broad based commercial truck inspection program, PG&E is being forced to comply with requirements intended to monitor operations that may not have PG&E's current standards. (Tr 64:6906.) Yet, PG&E had not looked into existing inspection procedures to determine whether the required 45 day inspection is compatible with PG&E's existing inspection requirements. (Tr. 64:6905.)

The Act expressly provides a procedure for those operations which believe that their existing inspection procedures are adequate. The department may, by regulation, provide for alternative inspection for particular types of vehicles or particular trucking operations. Despite the availability of this procedure to avoid or minimize inspection procedures which PG&E believes are unnecessary and unproductive, PG&E has not requested a different inspection interval than that provided by statute.

3. A biennial application fee of $400 per terminal.

PG&E estimates the annual cost to be $12,600. This estimate assumes that the terminal inspection fees, which are paid every 25 months, will next be paid in December 1990. But, as DRA's cross-examination points out, the fees will be due in December 1990 only if all initial terminal inspections had been completed by July 1, 1989. Tatarian, testifying in September 1989, did not know whether all terminal inspections had been completed. Without this information, we are at a loss to determine the actual revenue requirement.

In summary, PG&E has not met its burden of proof in support of the requested increase for motor vehicle inspections. PG&E's requested increase is denied.

d. <u>Account 592: Station Equipment</u>

FEA witness Miller noted a computational error in PG&E's workpapers, which when corrected, results in a $74,000 decrease in Account 592. PG&E, in its opening brief, states simply that "subsequent review shows the amounts shown in table 7-2 are correct and do account for the total $151,000." We do not find PG&E's abbreviated explanation to be convincing. Where a party alleges a computational error and fully explains how they traced the error, we expect PG&E to provide some explicit explanation of why they believe no error was made. PG&E did not do so in this instance. We adopt FEA's proposed reduction of $74,000 in Account 592.

e. Account 593.66: Pole Treating

DRA opposes PG&E's request for additional funds in Account 593.66 for pole treating, for the same reasons stated for Account 571.66. As we have previously explained, it is not appropriate to test poles which were funded but not tested in the past. We will reduce PG&E's request in Account 593.66 by $275,000.

f. Account 593.73: Tree Trimming

PG&E proposes two adjustments to this account for increased use of growth regulators and increased tree replacements. DRA accepts these proposed adjustments, while FEA opposes them.

As PG&E's witness testified, there is one particular growth regulator that PG&E is pursuing which it believes will be very successful. Approval by the Environmental Protection Agency is pending and PG&E expects approval by 1990. We disagree with FEA's contention that the approval and use of this regulator is too speculative. We will approve PG&E's requested increase of $231,000 for this purpose.

PG&E also requests an increase of $4,024,000 for an increase in tree replacement activity. PG&E replaced 748 trees in 2 pilot projects in 1985, and 913 trees in two other pilot projects in 1986. PG&E's request for $4,024,000 is based on the average tree replacement cost from the 4 pilot programs and an estimate from its tree-trimming coordinator that it will be possible to replace 6,500 trees per year beginning in 1990. PG&E does not describe tree replacement activity in 1987 through 1989.

We agree with FEA that neither PG&E's written or oral testimony sheds any light on the reasonableness of the estimate of 6,500 tree replacements per year. Yet, when the program is scaled up to a rate of 6,500 trees per year, it is reasonable to expect significant savings and efficiencies from the costs incurred under the pilot program. Therefore, we will authorize PG&E $3,000,000 to replace a minimum of 6,500 trees per year. If PG&E cannot replace at least 6,500 trees per year at the level we have funded, it should consider contracting the work to organizations, both profit and nonprofit, with experience in this area.

4. Customer Accounts

a. Account 901: Supervision

PG&E based its estimate for this account on 1987 recorded expense. FEA notes that this account has been declining over the past five years with only a slight fluctuation. FEA recommends a decrease of $333,000 below 1987 recorded expense, in order to reflect a continuation of this trend in the test year.[7]

PG&E acknowledges that this has been decreasing. PG&E explains that these decreases resulted from changes in management procedures, in which more people report to a single supervisor. PG&E believes that it will be difficult to further increase the supervisor's span of control and that no further decreases in this account are desirable. We agree with PG&E's explanation and accept its estimate for the test year.

b. Account 902: Meter Reading Expense

PG&E has estimated expenses in Accounts 902 and 903 by increasing the 1987 recorded expense by a factor which reflects the increase in customer growth. FEA states that these accounts have not correlated with customer growth over the past five years. While the number of customers have grown each year from 1983 through 1987, Account 302 actually decreased between 1983 and 1984 and between 1986 and 1987.

PG&E explains the decreases in Account 902 as arising from specific events in each period. We find PG&E's explanation credible. We will adopt PG&E's and DRA's estimate for Account 902, including an adjustment for customer growth.

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7 FEA projected a decrease in the labor component of this account from 1987 to 1988, and recommends 1990 funding at this level. All parties agree that the M&S estimate should be based on the 1987 recorded expense level.

We note however, that we do not necessarily accept PG&E's argument that it has reached the maximum potential of improvement in the meter reading area under the use of electronic meter reading. We expect PG&E to continue to examine every account, including the meter reading expense account, for new or additional opportunities to improve productivity and reduce costs.

c. Account 903: Customer Billing and Accounting

PG&E requests an increase of $1,303,000 in Account 903 to rewrite its billing, reporting, and customer data system (Customer Information System or CIS). PG&E explains that this system is over 20 years old:

> "This extended life has been possible by continually modifying and reprogramming critical subsystems and restructuring key programs to extend their lives. However, these extensions are taking longer to implement and are lasting shorter periods of time. The growing customer information base, increasing rate structure complexity, and available rate options are creating situations where CIS cannot be modified to respond to changes. In the long-term, a complete rewrite of the CIS computer programs is necessary to enable the company to manage future billing and reporting requirements." (PG&E Opening Brief, p.117.)

In support of the requested increase to rewrite the CIS program, PG&E submitted in evidence the "Feasibility Study for Replacement of PG&E's Customer Information System," prepared by Deloitte, Haskins and Sells (DH&S).

The DH&S report identifies an extensive number of functional requirements that are not addressed or not adequately addressed by the current CIS system. The Report then examines five alternative proposals for meeting PG&E's short-term and long-term CIS requirements, considering the resources, risks, advantages, and disadvantages of each alternative.

Two of the alternatives examined by DH&S involve maintaining the status quo and minimal maintenance of the current system. The DH&S Report finds these alternatives to be unacceptable because CIS cannot continue to function with only minimal maintenance in the long term (more than 2-3 years) and because it is approaching the maximum number of data elements allowed by the data base. DH&S concludes that a continued patchwork approach cannot address all of the fundamental functional and technical problems with the current system.

DH&S also examined the alternative of extending the life of the current CIS through a major restructuring, including main-frame processing of industrial billing. This alternative would allow PG&E to add new functions to CIS within the existing design and would allow the more critical user needs to be met in the short term. On the other hand, this alternative would not integrate the fragmented subsystems linked to CIS and would not correct all problems inherent in the current CIS design. In addition, this approach would require PG&E to divide the data base into regional data bases, making it more difficult to manipulate data on a system-wide basis.

The DH&S Report recommends a phased, "evolutionary" rewrite of the CIS system. Rather than a single new system with a delivery date several years away, DH&S proposes that PG&E divide the work into a series of subprojects to be delivered continuously over the life of the project. DH&S estimates the total cost of this effort to be $44,290,000, plus or minus 20%, to be incurred over seven years (1989-1995). Of the total, DH&S estimates that $21,540,000 can be met by redirecting existing resources to the rewrite effort. Thus, the incremental cost of replacement is $22,750,000. DH&S estimates the incremental expense in the test year to be $3,535,000.

Both DRA and FEA oppose this requested increase. DRA's witness testified that:

> "I'm recommending to continue the piecemeal patchwork procedure which has been satisfactory to PG&E over the past 20 years. Customers are

> being billed, customers pay their bills. They call in, they find the status of their account. The customers are not--I haven't seen an outcry from the customers for a new billing system of $44 million." (Tr. 9:854, Lubin/DRA.)

DRA believes "the existing CIS is performing satisfactorily now and can function adequately and economically in the future with continuing minor improvements as PG&E has done for the past 20 years." (DRA Opening Brief, p.19.) DRA also questions the DH&S recommendation to convert to IBM's DB2 database. Without reference to the record, DRA argues in its opening brief that the decision to choose IBM over Oracle is "ill-founded." DRA's reply brief further criticizes the choice of IBM, again with scant reference to the record.

In defense of the need for the CIS rewrite, PG&E cites the DH&S Report:

> "The System is difficult and inefficient to maintain. Any required change creates a maintenance crisis; a significant regulatory requirement, such as electric deregulation, could, most likely, not be incorporated. Information workers are frustrated with their inability to obtain the data they need to answer management's questions, rightly believing that a more modern system could better accommodate their needs and improve their efficiency.
>
> "Several underlying technological limitations built into the System are being approached; at the present rate of change, these limits will be reached within three years." (Exhibit 26, p. 1.)

We have carefully reviewed the DH&S Report, PG&E's testimony in support of the rewrite and DRA's testimony in favor of maintaining a patchwork approach to maintaining the current system. We have given little weight to the arguments against the rewrite which DRA raises for the first time in its briefs. Based on the evidence before us, particularly the careful evaluation of alternatives in the DH&S report, we find that there is a substantial likelihood that the current system is rapidly approaching its technological limitations and that it is not prudent to defer the decision on how best to replace or modify the system until the next general rate case. The phased rewrite of the CIS system is a reasonable approach to correcting the difficulties, limitations, and inefficiencies of a system which is nearing the end of its useful life.

Having found the proposed CIS rewrite to be reasonable, we must determine the appropriate cost estimate for the test year. DH&S suggests an incremental cost of $3,535,000 in 1990. PG&E is requesting $2,369,000. PG&E's request was developed and included in its application, as a "place holder," prior to the completion of the DH&S study. Although the consultant's estimate is higher than PG&E's request, PG&E is willing to "settle" for $2,369,000.[8]

DRA and FEA both challenge the reasonableness of the proposed expenditure. DRA voices concern over the discrepancy between the amount being requested in the test year and the higher costs projected by DH&S. DRA also observes that the DH&S estimate may be too low. DRA believes that a potentially more costly project deserves more careful review.

FEA believes that the cost of the rewrite is not known with enough specificity to be included in the test year estimates. FEA urges the Commission to remember that the consultant's projections are still estimates. While FEA questions these estimates, it is not opposed to PG&E recovering its actual expenses. FEA recommends a deferred account to record the actual

8 The consultant estimates an incremental cost in current dollars of $5,330,000 in 1991, $3,950,000 in 1992, and $2,985,000 in each year thereafter through 1985. PG&E's request of $2,369,000 in 1991 would be funded at the same level in 1991 and 1992, with attrition.

costs of implementing this program. DRA objects to a memorandum account. DRA states that the Commission should simply not allow the expenditures.

In evaluating the reasonableness of the requested increase in Account 903, we are not at all troubled by the fact that PG&E's request is lower than DH&S's estimated incremental cost. We agree with PG&E that the fact PG&E has made a more conservative request than the amount shown in the study is not a legitimate reason for rejecting funding for the project. We are pleased that PG&E has made a conservative request and that PG&E has committed to meet the additional costs from its own resources. By settling for the amount it initially requested, rather than the consultant's higher estimate, PG&E will absorb the risks of project delays or higher costs.

We will review PG&E's progress in the rewrite effort in the next general rate case, and we will consider the need for funding to complete the project. We caution PG&E that we consider PG&E's test year estimate (which will be carried forward to the attrition years), together with the DH&S estimate of incremental costs in 1993-95, to be the maximum amount ratepayers should be expected to contribute to this project. We will not consider a request for incremental funding beyond the time periods (1993-95) or amount ($2,985,000 annually for 1993-95) contained in the DH&S report.

Of the increase we authorize, $1,303,000 should be charged to the electric department.

5. Administrative and General Expenses

a. Segregation of Diablo Canyon A&G Expenses

Overview of Diablo Canyon Issues

The Diablo Canyon Settlement Agreement, adopted in D.88-12-083, provides as follows:

> "12. Segregation of Costs
>
> "A. For ratemaking purposes, all Diablo Canyon costs shall be segregated from other PG&E operations. No costs of Diablo Canyon shall be included in rates, except as provided in this Agreement. Diablo Canyon costs include any and all costs incurred by PG&E as a result of Diablo Canyon ownership, including but not limited to administrative and general expenses, operations and maintenance expenses, fuel-related costs, and any payment of the costs of accidents at other nuclear plants assessed to utilities owning nuclear plants.
>
> "B. PG&E shall keep full records, including reasonably contemporaneous accounts, to allow identification and auditing of all costs directly allocable to Diablo Canyon. These records shall be consistent with the Uniform System of Accounts and applicable accounting requirements of the CPUC." (D.88-12-083, mimeo. p. 144.)

The Implementing Agreement, which accompanied the settlement, expands on Paragraph 12:

> "Diablo Canyon operating and overhead costs will be segregated from other PG&E operations. Diablo Canyon costs shall include an allocation of franchise requirements and uncollectible accounts expense. The detailed methodology for allocation of common costs will be determined in PG&E's general rate case...." (D.88-12-083, App. D p.11.)

PG&E witnesses described the steps PG&E has taken to implement the above-cited terms of D.88-12-083:

> First, PG&E reviewed the Electric Plant Accounts to exclude $5.778 billion in Diablo Canyon direct plant costs.
>
> Second, PG&E reviewed its Nuclear Production O&M accounts, and removed $145,667,000 in base year 1987 expenses that historically have been directly charged to Diablo Canyon.
>
> Third, PG&E made adjustments for Administrative and General Expenses. According to PG&E, the total exclusion of Diablo Canyon related A&G is $65.2 million.
>
> Fourth, as this proceeding progressed, PG&E further reviewed common utility plant inside and outside the Diablo Canyon plant. PG&E identified an additional $3,728,000 in Diablo expenses reflecting charges and rentals attributable to the use of common plant, such as vehicles, aircraft, and the general office complex, by Diablo employees.

DRA agrees with PG&E's calculation of electric plant directly related to Diablo Canyon. With the exception of certain outside service expenses, DRA also agrees on the amount of Nuclear Production (Diablo Canyon related) O&M expenses to be excluded from 1987 expenses.

However, DRA and PG&E differ in two areas. DRA questions PG&E's estimate of the costs which will be incurred by PG&E as a result of Diablo Canyon in the test year for (1) administrative and general expenses and (2) common plant. TURN and FEA also differ from PG&E on the segregation of these costs.

We will address administrative and general costs at this point in the decision. The question of common plant is addressed in Section III.C.6.c, infra.

<u>DRA's Proposal to Segregate Diablo Canyon A&G</u>

As explained in DRA's direct testimony, "Administrative expenses consist of both direct and indirect items of expense. The items applicable to specific operations are first segregated and assigned directly to those operations." The Commission's long-established procedures for cost allocation require the utility to directly assign as many administrative expenses as possible. However, some administrative expenses are common to more than one operation within the utility. These indirect expenses are recorded in the "Administrative and General Accounts" 920 through 935.

Some indirect expenses have a significant relationship to a particular factor. For example, pension expenses are commonly allocated among the divisions and departments of the utility based on the ratio of pension expense to payroll. Other indirect expenses are sometimes so general in nature that no single factor would precisely allocate the costs. In these instances, we have traditionally applied the arithmetical average of the percentage of four-factors to allocate common costs within the utility. The four-factors commonly used to allocate common costs are:

1. Direct operating expenses, excluding uncollectibles, general expenses, depreciation, and taxes;

2. Gross plant;

3. Number of employees; and

4. Number of customers.

One of the traditional four-factors is "number of customers." Obviously, where Diablo Canyon has only one customer, a four-factor methodology which uses "customers" as a factor, would not accurately allocate Diablo Canyon A&G expenses. Therefore, DRA proposes that A&G costs be allocated between Diablo Canyon and the remainder of the electric department using a different set of factors:

1. Direct operating expenses;

2. Gross Plant;

3. Annual energy output, as a ratio of Diablo Canyon output to all generation and purchased power; and

4. Generation capacity, as a ratio of the nameplate capacity of Diablo Canyon to the nameplate rating of all of PG&E's generating units.

PG&E vigorously criticizes DRA's special four-factor allocation. We agree with many of PG&E's criticisms.

First, PG&E correctly notes that the use of "gross plant" seriously overstates Diablo Canyon's impact on A&G costs. Diablo Canyon, as a new plant, represents 36% of total plant because it has a higher historical cost than other older plants on the PG&E system.

Second, PG&E states that the use of generating capacity and annual energy output weigh the allocation too heavily toward the size of the facility, such that the use of both amounts to double counting. PG&E objects that DRA has removed factors which do have a causal connection to common costs, such as the number of employees, and replaced them with factors which allocate a disproportionate share of costs based on production. We agree with PG&E that generating capacity and gross plant, the combination of factors selected by DRA, weighs the balance too heavily toward the size of the facility.

Third, PG&E properly observes that the use of "annual energy output" is totally defective when the plant is not operating. We see no possible causal connection between the energy output and administrative and general costs. Indeed, if the plant is not operating and requires additional repairs, maintenance, and management attention, Diablo Canyon related A&G expenses might actually increase; yet, DRA's four-factors would decrease the allocation.

In summary, we find that three of the four factors in DRA's allocation do not bear a reasonable relationship to the costs to be allocated and are not a reliable means of estimating A&G expenses resulting from operation and maintenance of Diablo Canyon.

PG&E's Proposal to Allocate Diablo Canyon A&G

In order to segregate A&G expenses relating to Diablo Canyon, PG&E reviewed the 1987 Nuclear Production O&M accounts and identified $27.8 million in expenses charged to O&M that "typically" would be categorized as A&G expenses. Although PG&E had charged some A&G-type expenses to Nuclear Production O&M, some easily identifiable Diablo Canyon costs remained within A&G accounts. Therefore, PG&E reviewed its A&G costs and directly removed $26,563,000 from base year 1987. This adjustment consisted of costs which could easily be identified as related to Diablo Canyon, such as Property and Liability Insurance, Pensions, and Benefits.

Next, PG&E made an adjustment for "peripheral A&G" costs, a broad category of expenses incurred by PG&E as a result of Diablo Canyon, but not so easily segregated. PG&E removed $9,990,000 in peripheral A&G. This amount was based upon an estimate of peripheral expenses, presented jointly by DRA and PG&E in PG&E's 1987 test year general rate case. Although these costs were associated with several A&G accounts, PG&E deducted the total amount from Account 921.[9] Adding the $27,800,000 of O&M which would be typically categorized as A&G the $26,563,000 of easily identifiable costs and $9,990,000 of peripheral A&G results in a total of $64,400,000 in A&G expenses.

PG&E's estimate of peripheral A&G expenses is based upon an informal survey of various administrative departments conducted

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9 Since Account 922 is credited with administrative costs which are recorded in Accounts 920 and 921 which are transfered to construction, the effect of PG&E's allocation of all peripheral costs to Account 921, is to significantly increase the credit in Account 922. This accounting approach is not an accurate or fair method of segregating Diablo Canyon costs.

by PG&E witness Weingart in the fall of 1985.[10] In this survey, Weingart asked for a "judgment decision" on the part of certain department managers as to the percentage of their time and effort in 1984 which was related to Diablo Canyon. Diablo Canyon was not operating in 1984. Next, he asked them to project into 1987, based on the assumption that the plant would be operating in 1987, how this would change their workload related to Diablo Canyon. He then applied these percentages to the spreadsheet of 1984 recorded costs and 1987 estimated costs to develop a dollar estimate of A&G expenses for each department that could be associated with Diablo Canyon.

DRA and TURN argue that the informal use study is not a reliable basis for strictly segregating Diablo Canyon related costs in 1990. We agree with many of DRA's and TURN's criticisms of the use study:

1. The use study did not survey all executives, departments, and operations which would be expected to incur costs associated with Diablo Canyon. Although senior PG&E officers book their salaries to a subaccount of Account 920, none of the time or expenses of the president which related to Diablo Canyon was allocated through this study of peripheral costs. Weingart explains the omission as follows:

"Q Is that because the president isn't interested in Diablo, didn't spend any

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10 When the results were forwarded to DRA on November 1, 1985, PG&E stated:

"This information was gathered through an informal survey of the various administrative departments. This information is not available in the accounting records. The figures in the table should be considered preliminary. In particular, the estimates in the Corporate Communications area are incomplete." (Exhibit 294.)

> time on it, or what is the reason it wasn't allocated in that fashion?
>
> "A When we did the study we assumed that the job of president of the company was the overall running of PG&E. I would still say that is his job. And, therefore, we did not allocate any of his time to Diablo Canyon." (Tr. 51:5646)

Similarly, none of the time of the Board of Directors was allocated by PG&E to Diablo Canyon. Again, PG&E characterized the job of the Board of Directors as overseeing the running of the overall corporation, not any specific portion of the corporation. Thus, even when the President, the Board, and many of PG&E's other senior officers incur time or expense as a result of the ownership or management of Diablo Canyon, no effort is made to segregate such costs from other PG&E operations. This omission directly violates the terms of D.88-12-083.

PG&E, in its reply brief, argues that it is not required to charge to Diablo Canyon costs which result from Diablo Canyon operation, if the costs would be incurred by PG&E regardless of the existence of Diablo Canyon. Thus, PG&E reasons, even if a substantial portion of the "overall management" of the company is devoted to the operation of Diablo Canyon, it should not be charged to Diablo Canyon, because these salaries would be incurred even in the absence of Diablo Canyon.

PG&E's argument misreads D.88-12-083. PG&E should recall that D.88-12-083 separately allocates all revenues from the operation of Diablo Canyon. We did not subtract those revenues which would have been earned "regardless of the existence of Diablo." Similarly, we require PG&E to segregate all costs of ownership and operation of Diablo Canyon, without consideration of those costs which might have been incurred regardless of the existence of the facility. There are many demands on the time and talent of PG&E's senior management. Every hour of their time that is devoted to the operation of Diablo Canyon reduces the time available to focus on other aspects of utility operations, and thereby shifts the costs of managing the utility to other personnel.

PG&E characterizes the time and expense incurred by PG&E's senior management which is devoted to management of Diablo Canyon as "time devoted to the overall direction of the company." (PG&E reply brief, p. 127; emphasis added.) We agree that Diablo Canyon costs are costs of running the company. However, not all costs of running the company may properly be charged to ratepayers as cost of service. With the adoption of D.88-12-083 and the recent creation of PG&E Enterprises, PG&E is effectively divided into three distinct parts, a regulated electric and gas utility, the Diablo Canyon nuclear plant, and various unregulated subsidiaries (Enterprises). The separate functions are reflected in the Management Incentive Plan (See Section III.C.5.b(1) below) which describes "the company's three 1989 initiatives are to operate the utility in such a manner as to earn the full authorized rate of return; to operate Diablo Canyon safely, reliably and profitably; and to invest in suitable unregulated businesses." (Exhibit 76.)

Only those expenses incurred in the first of the company's initiatives, operation of the utility, are properly a cost of service to be charged to ratepayers. In past decisions, we have routinely recognized that not all costs of running a diversified company are proper ratemaking expenses and we have employed various devices to ensure that only that portion of senior management time devoted to running the utility is charged to the utility.

2. The survey was conducted before Diablo Canyon began operating. Certain department managers were asked to estimate the percentage of A&G in 1987, assuming the facility was operating. However, the numbers were merely estimates, and were not

a measure of actual operating experience. In defense of these estimates, PG&E argues that the 1985 use survey may understate Diablo Canyon expenses in such areas as ratemaking expense. PG&E's specific point is incorrect. According to Weingart, the informal survey inquired into expenses of only three accounts, (920, 921, and 923). Account 928, regulatory commission expenses, was not even within the scope of the use survey.

3. PG&E did not systematically document the responses. Many responses were verbal. There is no record of how the various estimates were derived. Notes of the interviews were not retained.

There is very little evidence in this record regarding the amount of actual time and expenses of corporate center personnel currently devoted to Diablo Canyon activities. However, the limited information that is available suggests that the estimates of expenses which were made in 1985 will not accurately reflect the actual allocation of costs to Diablo Canyon in 1990.

For example, the 1985 survey indicates that the Public and Employee Communications unit will incur only $1,000 in Diablo Canyon related expenses. Yet, according to the MIP, this unit will focus its delivery systems on messages that support three goals, one of which is operating Diablo Canyon efficiently and safely. Specific activities include semi-annual publications that report on emergency planning and monitoring activities for target residential audiences in the Diablo Canyon Public Education Zone. It is possible that these 1989 activities and expenses were known to PG&E when the survey was conducted in 1985, and that such expenses were somehow accounted for in PG&E's allocation of A&G expense. However, the burden of proof falls upon PG&E to reconcile the 1985 estimate of $1,000 with actual, current operating conditions which focus this department's initiatives on Diablo Canyon. In the absence of records to reflect how the 1985 estimates were derived, we must reject PG&E's use study as a basis for segregating common costs.

Beginning in 1990, PG&E plans to implement an improved direct charging methodology by which the great majority of corporate services peripheral A&G costs related to Diablo Canyon will be directly charged or attributed to Diablo Canyon, in a manner fully auditable by the Commission and consistent with the uniform system of accounts. While we applaud PG&E's plan to directly charge most common or peripheral administrative expenses, we are concerned that PG&E may misunderstand the criteria for directly charging such costs. As we explained earlier, all costs relating to the ownership and operation of Diablo Canyon must be segregated, including costs incurred at the highest managerial levels.

We stress that costs must not be charged to Diablo Canyon on an incremental basis. Under cross-examination, Mr. Weingart described how he instructed department managers to identify as peripheral A&G costs to be allocated to Diablo Canyon:

> "So it took a while to educate them that we were not looking for things that always that were specifically identifiable, but if they felt that there was some of there work that was involved to a certain extent with Diablo, took an extra calculation or something to that effect, that it should be included." (Tr. 51:5642.)

The reference to an "extra calculation or something to that effect" suggests that PG&E has taken an incremental approach to the allocation of Diablo Canyon costs. That is, if an employee performs a task with a purpose of benefits common to Diablo Canyon and other departments, the cost is identified and segregated only if consideration of Diablo Canyon requires an "extra" effort or expense. In D.88-12-083 we specified that all costs incurred by PG&E as a result of Diablo Canyon ownership shall be segregated and charged to Diablo Canyon. We did not state, nor did we in any intend, that only those incremental costs incurred by PG&E should be charged to Diablo Canyon.

Under PG&E's approach, if the preparation of an income tax statement which includes revenues from the operation of Diablo Canyon required the same number of calculations as the preparation of an income tax statement without Diablo Canyon revenues, then the tax department would charge no portion of its time, directly or indirectly, to Diablo Canyon.

PG&E's approach is incorrect. The cost of preparing an income tax statement for revenues derived from Diablo Canyon is clearly a cost of operating the facility and is a cost, for ratemaking purposes, which must be fully segregated from other PG&E operations. PG&E may segregate this cost by charging to Diablo Canyon the actual cost of the services provided, or if the services serve a common purpose, a proportional share of the costs. In this particular instance, the proportion of the cost of income tax preparation could be based on the proportion of revenue attributable to Diablo Canyon.

Another example of PG&E's mistaken approach to cost segregation is reflected in the testimony of Weingart:

> "Q Is any of your time charged to Diablo Canyon?
>
> "A No.
>
> "Q So none of the time you spent preparing your testimony appearing these past few days?
>
> "A I am testifying in the general rate case to determine general rates. I am specifically testifying to other than Diablo Canyon costs. I am not doing Diablo Canyon work right now. I am doing non-Diablo Canyon.
>
> That's what we're here to determine, non-Diablo Canyon expenses.
>
> "Q And none of your time has been over the past years as far as you know, charged to Diablo Canyon?

"A No." (Tr. 52:5706-5708)

We do not accept Weingart's reasoning. No cost is more clearly a cost of owning and operating Diablo Canyon than the cost of identifying expenses to be charged to Diablo Canyon. Although Weingart states that he is testifying to "other than Diablo Canyon rates," he can testify competently to "other than Diablo Canyon" costs only after having ascertained Diablo Canyon costs. The time devoted to determining Diablo Canyon expenses, and of presenting this determination to the Commission, must be charged to Diablo Canyon.

The very nature of A&G expenses is that they are often common to more than one function and therefore difficult to segregate. Virtually every item of common expense could be rationalized as Weingart has done to be a non-Diablo expense. For example, under Weingart's rationale, if a PG&E worker is dividing supplies, part of which are to be delivered to Diablo Canyon, that worker's time could be characterized as counting non-Diablo supplies, and thus none of that worker's time would be considered to be a cost of operating Diablo Canyon. (Of course, the converse could also be true. It could be said that this worker's time was devoted to counting Diablo Canyon supplies, and all of the time should be charged to Diablo Canyon.) In this example, where a cost is incurred for a common purpose serving both Diablo Canyon and non-Diablo Canyon operations, D.88-12-083 requires that the costs be fairly apportioned. For all common expenses incurred by PG&E at every level of management, we expect PG&E to fairly apportion the costs between Diablo Canyon and non-Diablo Canyon operations in proportion to the value of services rendered or the benefits received.

In response to ALJ Wheatland's request, PG&E reviewed all corporate center activities under the managerial level, and concluded that the great majority of corporate center peripheral A&G costs related to Diablo Canyon can be directly charged or attributed. PG&E plans to implement an improved system of direct charging of Diablo Canyon A&G expenses by the start of 1990.

In order to ensure that PG&E's improved system of direct charging fully allocates all costs of owning and operating Diablo Canyon to Diablo Canyon, consistent with D.88-12-083 and the terms of this decision, we will direct PG&E to file and serve a report in this proceeding, by March 31, 1990, which fully describes the standards, procedures and instructions employed by PG&E for directly charging or attributing all A&G expenses and common plant to Diablo Canyon. The report shall include all instructions, operating procedures or accounting guidelines which will govern reporting and recording of time and expenses incurred by employees who work outside the gates of Diablo Canyon, including employees at the managerial level.

In summary, while we endorse a system of direct charging and a direct use study as an appropriate basis for allocating common costs, PG&E's informal survey is neither timely, comprehensive, or rigorous enough to reasonably predict the A&G costs resulting from full operation of Diablo Canyon in 1990.

The Adopted Approach to Segregation of A&G Costs

According to PG&E, the real issue regarding Diablo peripheral A&G costs is "which method -- PG&E's use survey or DRA's special four-factors -- provides the Commission with a more accurate estimate of corporate overhead costs incurred by Corporate Services Departments on behalf of Diablo." (PG&E reply brief, p. 111.)

We see the real issue differently: Regardless of which method is more accurate, DRA's or PG&E's, is either method sufficiently accurate to ensure with reasonable confidence and fairness that all costs of Diablo Canyon will be strictly segregated in 1990?

The answer to this question is that neither method is reasonably fair or accurate. PG&E's study of peripheral costs is unreliable because it was informal, limited in scope, and poorly documented. The results are based on recorded data which is extremely dated and represents quite different operating conditions. The 1987 estimates are not a study of actual use. And Weingart's testimony raises doubt as to vigor of PG&E's effort to segregate all costs resulting from the operation of Diablo Canyon.

Nor are we convinced that the results of DRA's approach are accurate or fair. We find that three of the four-factors in DRA's allocation do not bear a reasonable relationship to the cost of being allocated and are not a reliable means of estimating A&G expenses resulting from Diablo Canyon.

What is the appropriate method for segregating common costs which are difficult to identify?

To answer this question, it is instructive to consider two earlier decisions involving PG&E. In a 1980 proceeding, Case 57202, staff proposed an estimate of A&G expenses based on a special two factor allocation. Staff used a two factor allocation, rather than the normal four-factor, because staff believed that the four-factor did not reasonably allocate costs to the small water division of PG&E. Thus, staff used "engineering judgment" to select two factors to allocate costs between this special small division and the remainder of PG&E. We adopted the two factor estimate. (D.91325, February 13, 1980.)

PG&E petitioned for rehearing of D.91325. In D.92861, we modified our prior decision to adopt the four-factor method of adopting common plant and expenses. We held that there had not been sufficient evidence to support the assumption that the special two factor method would be more reliable. We explained:

> "The most accurate, and thus, preferable method of making allocations of common utility plant...is on the basis of a study in which each item is allocated between departments or districts according to directly assignable use. Similarly, direct assignments to A&G expenses are preferable.

> "Use studies of common utility plant and studies looking to direct assignment of most A&G expenses involve a review of PG&E's overall operations, and require considerable staff or utility time and manpower to produce. Formerly, it was the practice of the Commission staff to conduct such studies at intervals of three to five years in connection with general gas or electric rate proceedings. In recent years our staff could not make available the necessary manpower to conduct such studies. Therefore, the four-factor method, formerly used only to make allocations of those items of A&G expenses which could not be directly assigned, has been used instead of full-scale studies." (D.92861, mimeo. p. 2a.)

In D.92681, we adopted the four-factors on an interim basis, and we directed PG&E to undertake a new, up-to-date, full-scale use study of common utility plant and of A&G expenses and to present such studies in the next general rate case.

Similarly, in the case before us, we find that the most accurate and preferable method of satisfying the requirement of D.88-12-095 that the costs of Diablo Canyon be fully segregated, is for PG&E to conduct a current, full-scale use study of expenses booked to Administrative and General Accounts, and to carefully and completely allocate such expenses between Diablo Canyon and other operations. We expect more than an informal, telephone survey. We expect PG&E to carefully develop a written format, to review the format with DRA and other interested parties, and to obtain itemized, documented responses from all departments, officers, and managers who record expenses in A&G accounts.

The design and format of the use study shall be reviewed by DRA and other interested parties in a workshop, to be moderated by CACD, in September 1990. The use study shall be completed and filed with the Commission by December 31, 1990. DRA and other parties may review and comment upon the study. Such comments shall be filed by March 15, 1991. Based on the submitted study and the comments of the parties, the Commission may, in its discretion, conduct further hearings to consider revisions to the revenue requirement for common plant and A&G for the 1991 or 1992 attrition years.

While there is a cost to PG&E and a burden on the Commission of verifying the study, it is absolutely necessary to establish a fair and accurate segregation of Diablo Canyon costs. It is not an exercise that will be performed very often, but it must be performed thoroughly and professionally at the outset of the Diablo Canyon approach. If revenues are to be strictly accounted and segregated (rather than estimated or four-factored), costs should be segregated with equal care.

As we stated above, the Commission considers the costs incurred by PG&E in determining the proper allocation and segregation of Diablo Canyon costs to be a cost resulting from the operation of Diablo Canyon. Therefore, all costs incurred by PG&E in preparation of the use study, as well as for participation in the workshops, and further proceedings on this issue, shall be charged to Diablo Canyon. The basic approach we are taking bears repeating: For all common costs incurred by PG&E at every level of management, we expect PG&E to fairly allocate the costs between Diablo Canyon and non-Diablo Canyon operations in proportion to the value of services rendered or the benefits received.

This is the first time the parties and the Commission have grappled with the exact means of segregating Diablo expenses and implementing that part of the Diablo Canyon settlement. Thus, we recognize the need for a degree of interim flexibility; although we expect a far more rigorous and thorough approach the next time this issue comes before us. Pending a complete, current use study of Diablo Canyon-related A&G expenses, we will make an interim allocation of expenses for 1990.

We have employed a five-step process to allocate A&G expenses common to Diablo Canyon and other PG&E operations.

1. We begin with PG&E's expense estimate for the test year, as reflected in the comparison exhibit.

2. We have added to the expense estimate, the amounts which PG&E has allocated to Diablo Canyon. These amounts fall into one of three categories:

   - **O&M:** Expenses allocated to O&M which PG&E believes would be typically categorized as A&G. These expenses were distributed among the various A&G accounts in the manner utilized by DRA in Exhibit 133.

   - **Direct:** Expenses directly charged to Diablo Canyon. These expenses were distributed among the A&G accounts by PG&E.

   - **Peripheral:** Expenses estimated by PG&E's 1985 informal use survey. PG&E's informal use survey focused on A&G expenses in three accounts, 920, 921, and 923. However, in estimating 1987 peripheral expenses, PG&E allocated these costs among eight A&G accounts, without an explanation of how the survey of three accounts was extrapolated to eight accounts. To complicate matters further, in this proceeding PG&E proposes to assign all peripheral A&G expenses to Account 923. For the purposes of this decision, we will distribute peripheral A&G among the A&G accounts, as set forth in DRA's Exhibit 133, which interprets PG&E's 1985 data response and PG&E workpaper DC-21.

3. By adding these various A&G expenses to PG&E's 1990 revenue request, we now have a picture of the overall level of A&G expenses which PG&E would have incurred had the costs of Diablo Canyon not been segregated. (Appendix D, Column H.)

4. Once we determined the overall level of A&G expenses (including Diablo Canyon costs) in each account, we reviewed all aspects of

each account and, where appropriate, made specific adjustments. (Column I.)

5. We next compared the the total of Diablo Canyon related A&G, as identified by PG&E (Column G), with the total A&G after after all other adjustments.

For four of the accounts (923, 924, 925, and 930.2), we will accept PG&E's allocation of Diablo Canyon expenses.

<u>Account 923</u>

This account includes the fees and expenses of professional consultants and others for general services which are not applicable to a particular operating function or other account. PG&E has identified $13,220,000 in Diablo Canyon O&M expenses which it believes would be otherwise attributable to this account. As we discussed earlier, if these expenses have been assigned to O&M, it would seem that they are applicable to a particular operating function and therefore not properly chargeable to Account 923. Nevertheless, we will give PG&E the benefit of the doubt in 1990. Accepting the O&M peripheral expenses removed by PG&E, we will make no further adjustment for Diablo Canyon related expenses in Account 923.

<u>Account 924</u>

PG&E has directly charged $7,685,000 of insurance expenses in Account 924 to Diablo Canyon. We are satisfied that PG&E has removed all insurance expenses resulting from the ownership and operation of Diablo Canyon.

<u>Account 925</u>

PG&E has directly removed $667,000 in Diablo Canyon expenses from Account 925. In addition, PG&E attributes a portion of its estimate of peripheral A&G costs to Account 925. The amounts removed from Account 925 appear to be a reasonable estimate for 1990. A major component of this account is third party claims. Since Diablo Canyon operates within a secured facility, we would reasonably expect third party claims to be lower than for other utility operations.

Account 930.2

This account includes the cost of labor and expenses incurred in connection with the general management of the utility not provided elsewhere. PG&E has removed 16% of the expenses from this account, approximately equal to the ratio of Diablo Canyon labor to overall company labor. As we noted earlier, some indirect expenses have a significant correlation to a particular factor. Historically, we have observed a strong correlation between certain A&G accounts and overall utility labor. Since Diablo Canyon labor is 16% of total company labor, we would reasonably expect Diablo Canyon's share of A&G expenses in this account, when properly segregated, to represent approximately 16% of total expenses. Therefore, we will adopt PG&E's estimate for Account 930.2.

For two accounts, Accounts 930.0 and 935.0, PG&E has removed no Diablo Canyon related A&G. In five accounts, PG&E has removed some Diablo Canyon expenses. The amounts removed by PG&E range from 7.6% to 12.3% of total A&G expenses in each of these accounts. Based on our review of these seven accounts, we find that the amounts allocated by PG&E to Diablo Canyon, if any, are likely to significantly understate the full extent of A&G costs resulting from Diablo Canyon operation.

Account 920

Account 920 includes the compensation of officers, employees, and other employees properly chargeable to utility operations and not chargeable directly to a particular operating function.

PG&E states that $12,516,000 of O&M charges can be imputed to be A&G expenses. We have difficulty in accepting this imputation. If the expense is known to be related to nuclear operations, it would seem to be the type of expense directly chargeable to a particular operating function. If the expense is directly chargeable, it is not properly classified as an A&G expense. However, for the purposes of this decision only, we shall give PG&E the benefit of our doubts, and assume that these O&M expenses would otherwise be charged as A&G. With this assumption, the total amount of Diablo Canyon A&G removed by PG&E is $15,871,000, or 12.3% of total A&G in Account 920.

As discussed above, PG&E's 1985 study understates the level of peripheral A&G in Account 920 for several reasons. While the compensation of officers is included in Account 920, PG&E's use study generally did not allocate officer's time to Diablo Canyon activity. Moreover, it is not clear that the coordinator of the survey nor those surveyed, understood the necessity for strict segregation of all common costs.

This is one of the A&G accounts which has historically reflected a causal correlation with overall labor expenses. Therefore, we will remove 16% of the total A&G expenses as the amount we reasonably expect to be chargeable to Diablo Canyon operations in 1990. The amount we remove credits PG&E for those expenses said to charged to O&M as well as PG&E's peripheral adjustment.

<u>Account 921</u>

This account includes office supplies and expenses incurred in connection with the general administration of the utility's operations which are assignable to specific administrative or general departments.

PG&E attributes $667,000 in O&M and $2,092,000 in peripheral A&G to Diablo Canyon, for a total of $2,759,000, or 7.3% of total A&G in Account 921.

As with Account 920, we would reasonably expect that the percentage of office supplies and expenses related to Diablo Canyon would correlate with the ratio of Diablo Canyon labor to total company labor. We will remove 16% of the total A&G expenses in Account 921 as the amount reasonably chargeable to Diablo Canyon, crediting PG&E for those amounts attributable to O&M and peripheral expenses.

<u>Account 926</u>

DRA takes exception to the Diablo Canyon adjustment of $18,211,000 for employee pensions and benefits. PG&E explained the calculation of Diablo Canyon pension costs as follow:

> "PG&E's Pension and Benefit expenses are dependent on the size of the company's workforce. Therefore, a labor-growth factor is used to develop an estimated year's Pension and Benefits expense. Initially, the Pension and Benefit estimate is developed assuming an employee population equal to the population in 1987. This estimate is then multiplied by the labor-growth factor (the estimated year's labor in constant dollars divided by 1987's recorded labor expense) to adjust for the forecast year's estimated employee level.
>
> "By keeping DCPP labor in the recorded-year denominator of this factor but excluding it from the estimated-year numerator, Pension and Benefits expenses related to Diablo Canyon are removed from the forecast." (Exh. 5, pp. 5-4.)

DRA believes that PG&E's adjustment understates the actual pension cost incurred by Diablo Canyon in 1987:

> "The Electric Department's percentage of Direct Labor for 1987 was 73.37%. Diablo Canyon's direct labor as a percentage of the Electric Department's direct labor was 16.06%. Therefore, pensions and benefits based on Diablo Canyon's direct labor should be $32.443 million ($275.238 million x 73.37% x 16.06%) for 1987." (Exh. 133, pp. 2-6.)

PG&E has not responded to the auditors' recommendation. Absent evidence to the contrary, it is reasonable to assume that the ratio of Diablo Canyon's pension expense to total pension expense should be approximately equal to the ratio of the Diablo Canyon labor force to the total labor force. Similarly the ratio of Diablo Canyon pension expense to total pension expense in 1990 should be approximately equal to ratio of the forecasted Diablo Canyon employee level to the total employee level.

PG&E's formula for calculating Diablo Canyon pension expense is likely to misstate the actual costs, unless there is a constant relationship between the size and cost of the Diablo Canyon labor expense between 1987 and 1990. A constant relationship is unlikely. We will adopt DRA's formula for Account 926.

<u>Account 928</u>

This account includes expenses properly includable in utility operating expenses, incurred by the utility in connection with formal cases before regulatory commissions. PG&E attributes $16,000 of peripheral A&G to this account. PG&E also indicates that $3,376,000 of expenses relating to Diablo Canyon were directly removed from the account in 1987. As set forth in this opinion, the issue of allocation of Diablo Canyon costs will continue before this Commission in 1990, and the time and expense which PG&E devotes to this issue must be charged to Diablo Canyon. In our view, Diablo Canyon related costs should represent at least 16% of the total expenses in this account. We will credit PG&E for the $16,000 of peripheral A&G attributed to this account. We do not credit the $3,376,000 directly removed in 1987, because this amount appears to be a nonrecurring expense associated with the start-up of the facility.

<u>Account 930</u>

This account includes research and development expenses. PG&E allocates none of the costs in this account to Diablo Canyon.

TURN, on the other hand, believes that R&D related to Diablo Canyon should be charged to Diablo Canyon. TURN recommends reducing PG&E's R&D budget by $1,111,000 to account for four projects whose descriptions indicate that the projects are intended to provide specific benefits to Diablo Canyon. TURN calculated the disallowance by multiplying total cost of these four projects by a factor equal to Diablo Canyon's share of the relative percentage of energy output forecast for the test year.

PG&E makes two different arguments against TURN's proposed disallowance. In its supplemental brief, PG&E argues that no causal relationship between Diablo Canyon and these four R&D projects has been shown. This argument is incorrect. Clearly, a portion of each project either involves research at Diablo Canyon or research related to nuclear power plants.

In its reply brief, PG&E does not deny a causal link. Instead, PG&E argues that TURN's allocation formula is incorrect, "when, in fact, very little of R&D work carried out in these projects is applicable to Diablo Canyon." (PG&E reply brief, p. 124.) This argument has more merit. However, it is not sufficient for PG&E to simply argue that the allocation overestimates the cost. As we have noted in numerous past decisions, if a party believes that a different amount should be adopted, it must offer evidence of the appropriate amount. In the absence of such evidence from PG&E on this issue, we adopt TURN's allocation.

DRA also proposes a Diablo Canyon related disallowance to Account 930 R&D programs. DRA believes that a portion of PG&E's Electric Power Research Institute (EPRI) dues be charged to Diablo Canyon. DRA has identified certain EPRI programs relating to the operation of existing nuclear plants which are exclusively of benefit to Diablo Canyon, and requests that the portion of EPRI dues corresponding to this portion of the EPRI programs be allocated to Diablo Canyon.

PG&E agrees that a portion of the EPRI budget relates to the operation and maintenance of existing nuclear power plants. PG&E also agrees that Diablo Canyon will be able to share and use PG&E's EPRI information. However, PG&E argues that the dues are not "a result of" PG&E's ownership of Diablo Canyon and therefore, none of the dues should be charged to Diablo Canyon. PG&E's

argument is premised on the assumption that D.88-12-083 defines Diablo Canyon costs as only those additional and separate costs which directly result from the operation of Diablo Canyon. PG&E's interpretation of D.88-12-083 is too narrow. In adopting the express terms of Paragraph 12 of the settlement, we intended to define Diablo Canyon costs to include administrative and general expenses. Such general costs are often common to more than one operation. Simply put, if Diablo Canyon utilizes the resources of the utility, that utilization incurs a cost and the cost is a cost resulting from the operation of Diablo Canyon.

PG&E also argues that the EPRI projects which benefit PG&E have a value far and away greater than the dues PG&E pays. If this is true, the corollary should also be true. Those projects which will benefit Diablo Canyon should have a value to Diablo Canyon far and away greater that Diablo Canyon's fair share of the dues. We will adopt DRA's adjustment of $2,982,000.

<u>Account 931</u>

Account 931 includes rents for property used by the utility for general and administrative functions. PG&E attributes $1,722,000 of peripheral A&G to this account. As we explain for Account 920, we expect that full segregation of Diablo Canyon A&G will result in a larger allocation, approximately proportionate to the ratio of Diablo Canyon labor expense. We will remove 16% from Account 931, and credit PG&E for the amount attributable to peripheral A&G.

<u>Account 935</u>

This account includes the cost assignable to customer accounts, sales, and administrative and general functions incurred in the maintenance of property. PG&E made no adjustment to this account. In Section III.C., we address the allocation of common plant and PG&E's system of direct charging. From this record, it does not appear that PG&E's system of direct charging provides for reimbursement of Account 935 expenses. In the absence of such evidence, an adjustment is appropriate for Diablo Canyon related costs. We will allocate a portion of the expenses, using the 16% formula applicable to Accounts 920 and 921.

Now that we have considered the segregation of A&G costs relating to the ownership and operation of Diablo Canyon, we will discuss other, non-Diablo Canyon adjustments to these accounts.

b. Account 920: Administrative and General Salaries

PG&E requests $113,405,000 in Account 920. PG&E's estimate for this account exceeds DRA's estimate by $24,700,000. Part of the difference is explained by the use of different "four-factors" and in differences in allocating the costs of Diablo Canyon discussed above. The remaining difference of $13,273,000 results from PG&E's request for additional costs to fund a new Management Incentive Plan. DRA, FEA, and TURN oppose this proposed increase. The MIP is discussed in subsection b.(1), below.

FEA expresses concern over PG&E's proposed in-house reprographics adjustment. FEA believes that the average $35,000 annual salary estimated for the ten new reprographics employees is excessive. FEA supports PG&E's decision to hire new employees to reduce the net costs of hiring outside vendors for reprographics, but FEA believes the net savings are understated because of the excessive salary levels. Generally, the Commission does not intend to determine the reasonableness of compensation for specific job classifications, particularly rank and file positions. That is a function we leave to the discretion of management. Therefore, we find the PG&E's estimated savings from in-house reprographics work to be reasonable.

(1) Management Incentives

Background

In 1983 PG&E implemented an incentive plan for management employees. In A.85-12-050, the 1987 test year general rate case, PG&E requested an increase of $2,209,000 to fund this management incentive plan (MIP). We considered the MIP in D.86-12-095:

> "[W]hile executive compensation is on par with the other utilities, we find merit in the staff argument that if PG&E's executives perform well enough to justify the 'bonus,' then there should be enough savings to pay for the MIP. We also note that PG&E does not disagree that MIP savings not only benefit the ratepayer, they also benefit the stockholder through increased corporate earnings. Accordingly, we believe that it is fair that the stockholder should bear some part of the expense of the MIP. We conclude that a 50/50 sharing of the MIP expense is reasonable. On this basis, we adopt an expense level of 50% of the MIP for the test year." (D.86-12-095, mimeo. pp. 55-56.)

We further ordered that the proceeding remain open for the holding of workshops on management efficiency and incentives, to develop a record which explores answers to specific questions including the following:

- o Should rules or guidelines be adopted to implement a program for the evaluation of management efficiency of utilities?

- o Are there common factors of unit price quality of service, salaries, productivity, and financial performance that may provide fair and effective measures of management efficiency?

- o Can efficiency guidelines encourage management innovation, ingenuity, and aggressive cost control performance? If so, how?

- o Is the equal sharing of costs and benefits a useful concept for management efficiency incentives? Can this concept be applied individually as well as company-wide or industry-wide?

The purpose of these workshops was to help us develop methods of fair, practical, and sensible management efficiency evaluation.

PG&E's MIP Proposal for the 1990 Test Year

In this proceeding PG&E requests funding for a new management incentive plan. The new plan merges and expands PG&E's previous management incentive and team award programs. Other than describing the general purpose of the new plan, PG&E's initial written testimony provided no details on the structure or operation of the plan.

PG&E originally requested $19,891,000 for funding the MIP. PG&E later reduced this amount by $1,775,000, associated with the Nuclear Power Generation unit, resulting in a revised request of $18,116,000.[11]

PG&E witness Weingart, under cross-examination, provided some additional details on the operation of the plan. The first explicit written description of the plan in this record was provided in PG&E's rebuttal testimony, Exhibit 64. Toward the close of the rebuttal hearings, PG&E also entered into evidence a copy of a data response to DRA, which contained a copy of the 1989 MIP and related information.

PG&E's rebuttal testimony explains the program as follows:

> "PG&E's Management Incentive Plan has two sets of goals: funding unit goals and corporate goals. The funding unit goals are negotiated between the funding unit lead officer and the chairman, vice-chairman, and president. This process of negotiation ensures that the goals are stretch goals and that they enable the company to focus on its mission to provide valuable, dependable, and fairly-priced utility services. Department goals for the MIP are negotiated between individual department heads and the funding unit lead officers, and are derived from the department head working closely with his or her employees. This

11 PG&E's revised request consists of $11,498,000 (electric), $6,596,000 (gas), and $22,000 (steam), for a total of $18,116,000.

process ensures that the goals are viewed as clear, measurable, and reasonable by the employees. These goals are also tied into PG&E's business strategy to provide a level of service that customers value.

"The corporate goals are currently based on corporate financial performance, as measured by corporate return on equity and by utility return on equity (ROE). These goals were adopted because they reflect the overall performance of the company. As is the practice with incentive programs, the goals were adopted with stretch goals target. The corporate goals were clearly communicated to employees, who have been provided many opportunities to become acquainted with the reasonableness of these goals. The corporate goals capture overall corporate performance, ensuring that funding units identify common interests and work together as a unified company to capture synergy and give PG&E an edge in the achievement of cost-effectiveness. Good performance on the ROE goals also ensures that the financial community regards PG&E as a good funding risk, which keeps the cost of capital for future investments low. This, in turn, reduces costs to our customers....

"Corporate ROE reflects the performance of utility operations along with that of non-utility operations. It is appropriate to use corporate ROE as a performance criterion because PG&E is one company and each part has an effect on the whole. The successful operation of Diablo Canyon will have a positive effect on PG&E's cost of doing business. For example, it will lower PG&E's cost of capital. This directly benefits the ratepayer through reduced costs reflected in our rates....

"For purposes of the MIP, every management employee belongs to one of 12 funding units, each of which has its own MIP fund. Generally speaking, the amount of an employee's incentive payout from the MIP depends: (1) on how much money ends up in the employee's MIP fund, which is a function of corporate and funding unit performance, and (2) on how well the employee and the employee's work group perform in reaching the goals of the funding unit.

"The size of the MIP payout distributed to any one employee is a function of the extent to which certain goals are reached. Before any incentive distribution is made, a certain level of goal achievement must be met either at the corporate or the funding unit level. This level is the 'minimum,' and functions as a threshold for fund generation. The stretch goal level of performance is called the 'target goal.' If the target goal level of performance is achieved, the majority of eligible employees will receive a payout of 5 percent. The highest MIP payout possible for the majority of employees eligible for the MIP is two items the 5 percent target. That is, a 10 percent award. This amount is distributed if the 'maximum' level of performance is attained....

"PG&E's position is that the MIP target fund, which is half of the maximum amount that can be expended under the MIP, should be funded 100 percent by ratepayers. If the performance exceeds the goal, the additional increment should be funded 100 percent by stockholders. If the target goal is not met, the difference between the actual payout and the target amount (which we request to be funded 100 percent by the ratepayers) should not be refunded to the ratepayer but should be used in the way thought fit by upper management." (Exh. 64, pp. 3c-5, 6, 7, 8.

The previous MIP included approximately 160 employees, including the Chairman, the President, and the uppermost officers. The new MIP includes all PG&E exempt employees, approximately 7,000 in number.

<u>DRA, TURN, and FEA oppose ratepayer funding of the MIP</u>

In the previous general rate case, DRA had opposed funding the MIP for several reasons. These reasons are summarized in D.86-12-095:

"Staff argues that although the goals appear to be admirable ones, and although the company has performed rather well in the years since MIP

> was instituted, the staff is nevertheless of the opinion that the plan should not be funded by the ratepayers because it is simply not needed.
>
> "With regard to two of the goals, return on equity and market-to-book ranking, staff argues that there is really no relationship between these items and the interests of PG&E ratepayers. Staff submits that the company's earning of a high return on equity is probably inimical to the interests of the ratepayers, since their bills are the primary source of this high return and favorable market-to-book ratio. (Exhibit 51, p. 10-B-3.) Further, staff points out that the company is substantially protected from large adverse swings in its return on equity by the existence of the Commission's Energy Cost Adjustment Clause and Gas Adjustment Clause procedures which enable the company to recover fluctuations in fuel prices without filing for a rate increase.
>
> "Staff discusses the other MIP goals in its brief and concludes that PG&E has not set stringent enough Ratepayer Goals to make the MIP a genuine challenge for corporate management to meet.
>
> "Further, according to staff, the company has failed to demonstrate any causal relationship between the existence of the MIP and its achievement of the stated goals therein. And staff also questions whether there is really a genuine need for such a program, 'given the already high level of PG&E's executive salaries.'
>
> "Finally, staff argues that if the company indeed performs well enough to justify the award of bonuses (according to the criteria delineated in the MIP), it should experience significant enough savings to pay for the cost of the MIP program." (D.86-12-095, mimeo. pp. 54-55.)

DRA opposes funding of the new MIP for essentially the same reasons. DRA further objects that ratepayers would be compelled to contribute to the MIP regardless of the actual performance or payout of the program, while shareholders would only "share" in funding the program if the MIP exceeds the target funding level.

DRA also observes that the performance of Diablo Canyon and PG&E Enterprises, as a component of overall corporate ROE, will influence the amount of incentives paid under the MIP. According to DRA, both Diablo Canyon and PG&E Enterprises must be excluded from base rate revenue requirements.

FEA opposes the inclusion of MIP costs in the test year operating expenses for a number of reasons:

> "First, the FEA does not see any indication that this plan is required in order for the Company to earn a reasonable return on its rate base as well as to recover its reasonable operating expenses. Second, it appears that if these goals are met, the savings generated should more than pay for the costs of the program. Yet another reason for FEA's opposition is the real possibility that the funds, even though collected by the Company, may never be paid out. This in fact occurred in 1988. A fourth reason for opposing this inclusion relates to the difficulties inherent in attempting to quantify and divide the benefits and savings, if any, between the ratepayers and the shareholders. FEA's final reason for opposing the inclusion of the MIP costs relates to the fact that the workshops which the Commission ordered held in the Company's last proceeding were not held." (FEA opening brief, pp. 15-16.)

TURN opposes ratepayer funding of the MIP for three reasons: First, the MIP includes goals which do not advance ratepayers' interests. Second, PG&E is not required to expend allocated funds authorized for this program. Unspent funds can result in a gift from ratepayers to shareholders. Third, TURN firmly believes that management will have the greatest incentive to perform well if its compensation is based on performance and not insured by ratepayer funding.

Discussion

As we stated in D.86-12-095, "the concept of cash incentives for success and cash penalties for poor performance is neither new nor unique." (D.86-12-095, p. 56a.) We recognized the potential value of properly formulated management incentive programs and concluded that methods for fair, practical, and effective management efficiency evaluation should be developed. We ordered that the proceeding remain open for further workshops to develop a record regarding the formulation of such incentives.

The workshops were not held. The record which we had hoped would be developed in these workshops is obviously not available. In the absence of a more developed record, we must evaluate PG&E's request for increased funding of its new MIP based upon the record PG&E has provided in this proceeding.

We first consider the need for increasing employee compensation levels by $18,116,000 to fund the MIP. In this decision, we authorize an overall labor expense of $ 573,740,000. This labor expense, together with other forms of compensation included in PG&E's overall request and authorized by this decision, will allow PG&E to provide employee compensation at the level necessary to provide safe, reliable service at the lowest reasonable rates. We have also extended to PG&E considerable flexibility in administering the total labor expense. This flexibility allows PG&E to put a portion of the expenses designated for salaries at risk, and make such payments in the form of bonuses or awards.

Since we find that the authorized labor expense and other compensation expenses provide an overall compensation level which is reasonable, is there justification for including an additional $18,116,000 in the cost of service?

From the evidence before us, there is already adequate revenue to fund the new MIP. PG&E has launched the new MIP in 1989 and is capable of funding the program, either within the currently authorized labor expense, from currently achieved savings in other accounts or from the benefits derived by shareholders from increased efficiency. PG&E has not explained why it is necessary to increase Account 920 in 1990, when the new MIP is adequately funded in 1989 at the current expense level.

PG&E argues that if base pay is at or below market levels for many managerial employees, an incentive plan is an essential component of total compensation in order to reach a level that will attract and retain qualified employees. However, PG&E has not offered any evidence that base pay for management employees will be at or below market levels in 1990. Instead, PG&E states that executive, managerial, and non-exempt wage increases lagged the market in 1987 and 1988. PG&E characterizes the difference between the rate of PG&E management pay increases and the rate of increases in the "average market" to be "savings." If PG&E intends to imply that the moderation of pay increases has resulted in underpaid management employees, the evidence it offers is insufficient to prove the point. In the last general rate case PG&E presented testimony that executive and management salaries were 4% and 8% above utility salaries, respectively.[12] Thus, even if PG&E has moderated the increases in management compensation, there is no basis on which we can conclude that such moderation has reduced management salaries below market rates.

In support of the proposition that management employees may be underpaid without the MIP, PG&E also cites DRA's

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12 In D.86-12-095, we concluded that the utility labor market is the relevant market for comparing salaries of most job categories. (D.86-12-095, mimeo. p. 45.)

compensation study. DRA's study shows executive compensation to be 4.85% "under market." PG&E witness Weingart testified:

> "I know that the company has certain problems with the staff's compensation exhibit. But even in the staff's compensation exhibit it is my understanding that employees in the management level at PG&E are not being shown as paid more than the average for other companies." (Tr. 10:975.)

Apart from the question of whether staff's compensation study is methodologically correct, we have considerable difficulty reconciling Weingart's testimony with PG&E's position on clerical compensation. Even though DRA's salary showed clerical compensation to be "above market," PG&E argued that clerical workers were not necessarily overpaid. According to PG&E, "As long as the aggregate base salaries remain within the 'band of competitiveness' that companies pay should be considered competitive." (Exhibit 64-3, pp. 3a-5.) PG&E believes that the "band of competitiveness" ranges 10% above and below the survey median. Therefore, by PG&E's criteria, as long as PG&E's management compensation falls within 10% of the survey median, as it does in this case, such compensation should be considered to be competitive.

In addition, PG&E's argument addresses only base salaries for management employees. Base pay is only one element of a compensation package which, in total, influences PG&E's ability to attract and retain qualified employees. PG&E did not offer evidence in the relative change of overall management compensation.[13] As PG&E itself notes, "we cannot conclude from

13 Although base salaries are alleged to have "lagged" market rates in 1987, this measure of salaries does not take into account increased benefits, such as an expanded MIP, which were added to management compensation in 1987.

DRA's Exhibit 107 [compensation exhibit] whether PG&E's compensation, with MIP, exceeds or even matches the base plus incentive compensation of the companies against whom PG&E must compete for management talent." The burden for offering such evidence, clearly a prerequisite to increasing authorized expenses for management compensation, falls on PG&E. In the absence of such information, we have no basis for finding that it is necessary to increase Account 920 for funding additional incentives in the test year.

PG&E also argues that an increase in funding for the MIP is justified because these costs are more than offset from savings which may result from the MIP. PG&E states that the "savings and incentive costs associated with the target level goals of the MIP are already incorporated in the Application." However, PG&E has not quantified the savings which will result from the expanded MIP. Instead, PG&E points to the overall estimated productivity savings of 2.7%, which are incorporated in PG&E's overall general rate request. The overall request and associated savings in this Application were developed in conjunction with PG&E's business plans. The target level goals were designed to support the objectives of PG&E's business plans. Therefore, PG&E concludes, the savings associated with the target level MIP have been incorporated into the Application.

We note that the target goals of the MIP were developed and distributed to employees for 1989 long after the application was prepared and filed. Goals for 1990 have still not been set. PG&E's explanation fails to demonstrate to us that greater savings or efficiencies will result with the MIP in the test year than without it.

In Section III.F of this decision we set a productivity goal for PG&E. If PG&E attains the goal it will earn its full authorized rate of return. PG&E does not explicitly state how the target levels of the MIP are set. We assume that such target levels are set to achieve the fully authorized rate of return and return on equity (ROE). Thus, the target level for corporate ROE and utility ROE is the fully authorized ROE level. The target level for funding unit cost containment and staffing goals is the budgeted level. There is no direct financial benefit to ratepayers from PG&E meeting its target goal under the MIP.

We recognize that ratepayers will indirectly benefit in the long run from vigorous cost containment and cost reduction by utility management, but the relative benefits under PG&E's MIP are so overwhelmingly weighted in favor of shareholders, it would not be just or reasonable to require ratepayer contribution above the amounts otherwise authorized for base pay in this decision.

On the other hand, if PG&E does not meet its target goal, shareholders will earn something less than the authorized rate of return, and the full target fund will not be paid out. In this instance, PG&E proposes that shareholders should be allowed to keep the funds that were not paid out, to defray the earnings that were not realized. In effect, PG&E's proposal is to use the MIP as a hedge for shareholders against inefficient management.[14]

While PG&E's request does not include funding for awards to employees who work in the NPG funding unit (Diablo Canyon) or at PG&E Enterprises, it is clear that the structure of the entire incentive system is weighted heavily toward the performance of these two units. In 1989, for example, each department in Corporate Communications will be making special efforts "designed

14 PG&E states in Exhibit 64: "The ratepayer has achieved the savings from the target level of performance. . . . The ratepayer should pay for the savings he received. . . ." The total authorized expenditures to cover operating costs for the test year incorporate an estimate of productivity savings which we believe PG&E can reasonably obtain. The incentive we offer PG&E to obtain this estimated savings is the reasonable opportunity to earn a fair rate of return. We reject PG&E's argument that ratepayers should pay anything more for PG&E's success in attaining the estimated productivity savings.

to support the three main corporate priorities: earning the authorized rate of return on utility operations, operating Diablo Canyon safely and reliably, and investing in suitable unregulated businesses." We find that the costs of initiatives to meet two of the three "main corporate priorities" (Diablo Canyon and unregulated business investments) are not an appropriate cost of service. D.88-12-083 requires all costs incurred as a result of operating Diablo Canyon to be segregated, not just the direct salary of Diablo Canyon employees, but also the salary, expenses and incentive bonuses paid to other PG&E employees (such as those in Corporate Communications) who devote time or effort to this corporate priority. Similarly, we expect strict segregation of all costs incurred in pursuing unregulated business activities, both the direct salaries of Enterprise employees and the salaries and expenses of other employees who contribute to this effort.

Another part of the financial goals concerns us. Corporate ROE, a primary goal of the MIP, is based in part on the the performance of Diablo Canyon and PG&E's unregulated subsidiaries. We believe that it is inappropriate for ratepayers to underwrite incentives based on the performance, cost, or quality of service of PG&E's non-utility operations. Incentives paid to achieve profitable operation of Diablo and PG&E Enterprises, or to provide better corporate center service to these particular ventures, is not a justifiable cost of service for California ratepayers.

We have also examined the nonfinancial goals of the MIP. Again, we find very little in the program presented by PG&E that can be said to be of direct benefit to ratepayers. In fact, we find some funding unit goals to be questionable, regardless of who funds these goals. In particular, we have strong reservations regarding incentives which are targeted to specific regulatory results. As we understand the plan, the rating of employees in certain funding units will depend on the degree to which Commission decisions reflect PG&E's position in particular proceedings. Thus, if we do not adopt PG&E's positions in a particular proceeding, the incentive compensation that would otherwise to paid to the PG&E employees who advocated the position will not be paid to the employee but instead will be retained by the shareholders. The Commission believes that management should be compensated for its skill and experience, but the specific level of individual employee compensation should not be based on the outcome of a particular proceeding.

In summary, the Commission endorses the concept of management incentives. We believe that such plans can be part of a sound management strategy to attain corporate goals and objectives. However, in this proceeding we find that PG&E already has the resources and the flexibility to implement the proposed MIP in the test year without the need for additional funding or the creation of a special MIP fund. We also find that many of the financial and non-financial goals of the individual funding units are only remotely related to improving or maintaining the quality of service to ratepayers. We reduce PG&E's request in Account 920 by $17,316,000 to reflect disallowance of the increased costs of the MIP.[15] We will continue to authorize funding for an MIP at the level adopted in the last general rate case.

PG&E states that it would be unfair to disallow expenses for the MIP simply because the workshops did not take place. We do not disallow expenses the MIP because workshops were not held. While workshops were not held, our desire for a more complete record on the question of management incentives was made manifestly

15 $1,263,000 (1987 $) is currently authorized in rates for the former MIP. Of this amount, PG&E conducted $800,000 from its estimate of Account 920. We credit PG&E's overall request with the $800,000 it deducted, so as to maintain funding of the MIP at the level previously authorized.

clear. We were therefore disappointed that PG&E's affirmative showing in support of a 1,400% increase in funding consisted of just three short paragraphs. At a minimum, PG&E's affirmative showing should have consisted of a reasonably detailed description of the new program and a direct response to each of the questions posed by the previous decision.

Our order directing that further workshops be held is still outstanding. We direct CACD to schedule workshops in the near future. This proceeding will remain open for these workshops on management efficiency and incentives.

c. Account 923: Outside Services

Account 923 includes the fees and expenses of professional consultants and others for general services which are not applicable to a particular operating function or to other accounts. Account 923 also includes the pay and expenses of persons engaged for a special or temporary administrative or general purpose.

PG&E's estimate exceeds DRA by $6,653,000, due to use of a different methodology for estimating base expenses in this account. Before we discuss the 1990 forecast, we will review the difficulties encountered by DRA in obtaining an accounting of PG&E's outside service expenditures in 1987.

In November 1988 DRA requested a listing of outside services in 1987, with the accounts to which the amounts were booked. On December 30, 1988, PG&E provided a copy of FERC Form 2. In providing this list, PG&E explained:

> "This report is preliminary, in that it is subject to verification and change. It is the result of a substantial effort, and it represents the most complete data available at this time. Due to the volume of information and the number of documents that have to be examined to obtain this type of data, PG&E requests that staff focus on specific and significant vendors or charges in further data requests, if more information is needed, rather than on the list as a whole."

DRA informed PG&E that this response was unacceptable. For all expenses on Form 2, DRA asked PG&E to identify the FERC account number, the activity code, a brief explanation of the expense, and the project number (if applicable).

Between January 12 and March 7, 1989, PG&E provided three addendums to its initial response, containing a more detailed breakdown of outside services.

As of of March 17, 1989 PG&E still had not identified more than one third of the booked expenditures in Account 923 in account level detail. ALJ Wheatland directed PG&E to identify these costs.

By May 10, 1989, PG&E was able to identify by vendor, activity, and FERC/PG&E accounts, all but $1,600,000 of expenditures for outside services. Of the $18,900,000 charged to FERC Account 923, PG&E was able to determine all but $400,000 in account level detail. PG&E states the remainder consists of $250,000 in costs incorrectly charged to Account 923 that will be reclassified to other accounts, and $150,000 in net accruals and reversals.

DRA believes that the fact the information was finally provided does not end the problem. DRA did not receive the final accounting until May 10, by which time, according to DRA, it was too late for DRA to analyze the information.

According to the FERC Uniform System of Accounts, the account should be maintained so as to permit ready summarization according to the nature of the service and the person furnishing it. In the case of outside services, it has taken PG&E six months to provide information which should have been readily summarized in account level detail.

Had PG&E provided a timely response to DRA concerning 1987 expenses, allowing DRA a reasonable period of time to review the actual 1987 costs, we would typically use 1987 recorded expenses as a base year and escalate costs for customer growth.

However, as a consequence of PG&E's delay in providing an accounting of Account 923, we cannot conclude that 1987 recorded expenses form a reasonable basis for estimating expenses in the test year. Instead, we will adopt as a base estimate, the amount authorized for Account 923 in the previous general rate case, and escalate this base estimate for customer growth.

PG&E proposes two adjustments to the base estimate. We adopt the proposed decrease for reprographic expenses. We adopt the proposed increase for the FAMIS system.

d. Account 925: Injuries and Damages

This account includes amounts for uninsured losses, the cost of insurance premiums for third party claims and workers compensation insurance. PG&E estimates 1990 expenses using a straight-line trend of the last five years of recorded uninsured losses, and then added to this estimate the settlement of one specific claim (the Carmen settlement). The Carmen settlement involved injuries sustained by a married couple from an accident in October 1986. The company settled this claim by agreeing to pay $5,000,000 in 1988 and $3,100,000 on January 1, 1990. PG&E has added the 1990 payments to the estimate developed by the trend line.

PG&E urges that we allow the added $3,100,000 in 1991 and 1992, as well as 1990, as a means of offsetting other claims that are expected to rise in these years.

DRA and FEA agree that the 1990 settlement payment is an appropriate test year expense, but do not believe this expense should be carried over to 1991 and 1992. DRA would deduct this expense in the attrition years. FEA proposes that the cost be amortized over three years.

In the previous general rate case, PG&E requested $31,948,000, DRA recommended $27,052,000, and we adopted $31,309,000 in Account 925 for test year 1987. PG&E's recorded expenses in 1987 were $28,049,000.

PG&E's estimate for Account 925 in 1990 is $37,843,000. This estimate is a 33% increase over three years. The record in this case does not justify the assumption that the account will rise at such a rapid rate.

Accordingly, we will adopt a base estimate of expenses for Account 925 of $34,743,000. We will also adopt FEA's proposal to amortize the 1990 Carmen settlement payment over three years. This results in an authorized expense of $35,776,000 for Account 925 in the test year.

e. Account 926: Pensions and Benefits

PG&E's estimate of Account 926 exceeds DRA's estimate by $35,408,000. Differences arise in four areas:

(1) **PG&E proposes an Increase of $10,229,000 for Prefunding of a 401(h) Plan**

As of 1987, the present value of PG&E's retiree medical liability was approximately $900 million. Of this amount, approximately $500 million is allocated to the potential medical liability of current retirees and the past service of current employees. The remaining $400 million represents the projected future benefits of current and future employees.

PG&E proposes to begin advance funding of the liability by using a "401(h)" account within the Pension Trust Fund. PG&E believes that advance funding will more properly allocate costs among generation of ratepayers and reduce the pressure for significant rate increases in the future. In addition, PG&E believes that advance funding will reduce the impact of the liability on the company's financial statements.

The Financial Accounting Standards Board (FASB) is currently considering a proposed accounting standard on post-retirement medical benefits. PG&E anticipates that the rule will require financial statement disclosure of the unfunded liability. Thus, PG&E's proposal to begin funding the liability now will reduce the amount required to be reported when the final standard is adopted.

DRA is opposed to prefunding at this time. According to DRA, it is uncertain whether the new FASB standard will require prefunding of post-retirement benefits, when the standard will be effective, whether 401(h) will be the appropriate investment vehicle to satisfy FASB, and whether PG&E is proposing an appropriate amount to be prefunded over the next three years. DRA believes that the Commission should not approve funding of 401(h) accounts until after the new FASB standard is issued and the Commission has conducted an OII.

We agree with DRA that it is premature to begin funding of a 401(h) program in anticipation of a FASB standard that has not yet been finalized. Although both PG&E and DRA refer to and interpret the exposure draft, neither party offered it into evidence. Therefore, it is difficult for us to evaluate the reasonableness of PG&E's prefunding proposal in light of the proposed standard. However, it is possible that the methods of expensing post-retirement medical benefits may differ materially from those proposed in the FASB exposure draft. It is also possible, once the new standard is finalized, that 401(h) may not be the most effective method of satisfying the new standard. Given the magnitude of the potential unfunded liability and the relatively minor contribution PG&E proposes to make over the next three years (less than 1% per year) we see no harm to ratepayers or to PG&E's financial statements by deferring a decision on prefunding until the new FASB standard has been finalized. In anticipation of the issuance of the new standard, we will leave the record in this case open, to consider a possible addition to the revenue requirement, once the standard is finalized.

(2) <u>Pension Plans</u>

PG&E's estimate of pension plan expenses exceeds DRA's estimate by $7,555,000.

PG&E uses pension contribution as the basis for rate recovery. DRA believes that PG&E's method is incorrect. DRA argues that PG&E should "request only the expensed amount, not the maximum allowable contribution."

DRA has offered extensive argument in support of its position that FASB 87 is uniquely appropriate for determining the pension plan revenue requirement. We will not repeat DRA's arguments here. In D.88-03-072 we gave detailed consideration to DRA's arguments in support of using FASB 87 for ratemaking purposes. We did not adopt DRA's position. Instead, we concluded that pension costs should continue to be based on the aggregate cost method for ratemaking purposes.

> "The Statement will not be adopted at this time. However, as with any accounting convention, we recognize that future circumstances could warrant reconsideration of this decision as experience is gained under the Statement, as regulatory policies are reviewed, or as the Statement itself is amended." (D.88-03-072, mimeo. p. 12.)

In this proceeding DRA has offered no new facts or circumstances which would warrant reconsideration of D.88-03-072. Based upon our findings in D.88-03-072, we conclude that it is reasonable for PG&E to use a "contribution approach" to calculating pension costs in the test year.

While we adopt PG&E's methodology for calculating pension benefits, we agree with DRA that PG&E has not met its burden of proof in supporting the reasonableness of the discount rate and wage increase assumptions. It is not sufficient for PG&E to tell us that these assumptions represent the actuary's best estimate. When challenged by DRA with evidence of lower historical trends, PG&E should explain why the actuary's estimate is sound. In this instance, PG&E has not done so. While we would prefer to adopt PG&E's methodology with DRA's alternative assumptions of a 7% discount rate and a 5.5% wage increase, we are unable to independently run PG&E's pension cost model. We are thus unable to adopt a revised pension estimate using DRA's alternative assumptions. In future cases, DRA is advised to request from PG&E and enter into the record alternative pension estimates using any alternative assumptions that DRA may propose.

(3) <u>Medical Plans</u>

PG&E estimates gross medical plan expenses for the entire company to be $125,859,000 in 1990. Of this amount, PG&E estimates electric department medical expenses, net of expenses allocable to Diablo Canyon, to be $59,077,000.

Medical plan expenses include the cost of coverage provided by Blue Cross, Blue Shield, Medicare Supplemental Plan, Flexible Compensation Plan, Prescription Card Service, Substance Abuse Pilot Program, and eleven Health Maintenance Organizations (HMO). The Blue Cross and Blue Shield plans are self-funded plans (indemnity plans). To estimate these costs in 1990, PG&E started with the recorded 1987 claims, and then projected these costs using a trend factor developed by William H. Mercer Meidinger Hanson, Inc. HMO estimates were based on historical trend data for the Kaiser Plan, since Kaiser members represent 74% of all HMO participants.[16]

The estimated trends utilized by PG&E to project medical costs are 14.3% per year (1988-90) for the medical costs of PG&E's indemnity plans and 11.4% per year (1988-90) for the HMOs. The analysis upon which this trend is based was not placed in evidence. Instead, the basis of the trend was briefly summarized in Exhibit 6, sponsored by PG&E witness Kozel. Kozel is Acting

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16 It is not clear whether projected HMO costs were based solely on historical data, or whether the estimate derived from historical costs was also increased by PG&E. Kozel testified: "historically the trend in HMO has been about 8 and we are projecting they are going to increase about 11.4." (Tr. 57:6259.)

Director of the Benefits Section of PG&E's Compensation and Benefits Department. Kozel's testimony states that "the medical trend takes into account several emerging medical issues that will have an effect on PG&E's medical plans." Although these factors are identified in Exhibit 6, this testimony does not explain how these other factors were derived or weighted in relation to historical costs.

In PG&E's rebuttal testimony, Exhibit 64, Kozel provides some additional information regarding the medical trend estimate prepared by the consultant. Here, Kozel explains that PG&E believes that

> "It is more appropriate to look at historical costs for medical coverage and project future costs using an annual average percentage of change. PG&E used 10.8%, its annual average percentage of change from 1983 through 1987. In addition...PG&E considered other factors such as current costs of medical inflation, cost shifting and utilization changes that were not included in historical costs because they were emerging issues. These factors increase the historical percentage to 14.3%." (Exh. 69, pp. 43-1.)

Although this rebuttal testimony helps us understand that the trend was developed from historical data, which PG&E increased by nearly one-third to account for increased costs that are not adequately reflected in historical costs, it is still not clear why these particular factors are expected to increase the estimate derived from PG&E's historical costs by such a significant magnitude.

DRA has also developed an estimate of medical costs. At the time DRA prepared its estimate, the recorded medical costs for 1988 had become available. Therefore, DRA applied its estimate to 1988 recorded medical costs.

On its face, DRA's method seems quite simple. DRA started with the 1988 recorded medical expenses and escalated them by the weighted average increase in all medical premiums for 1989. However, just as the basis for PG&E's trend is not well explained, the detailed derivation of DRA's methodology is difficult to comprehend. DRA claims that its method mirrors the calculations used by PG&E's actuary, and supports this claim with references to data requests or responses which are not in the record.[17]

PG&E's rebuttal testimony criticizes DRA's approach for relying on premiums. PG&E pays premiums only to HMOs. PG&E's indemnity plans are self-insured, which means that PG&E does not pay premiums for these programs. In response, DRA states in its opening brief that it has not relied solely upon premiums, but that its estimate is calculated from both the HMO premiums and the accrual rates of the indemnity plans. Unfortunately, it is not apparent from this record how DRA used the accrual rates to develop its trend. At the same time, PG&E has not offered evidence to refute the specific premium/accrual rates utilized by DRA for projecting 1989 expenses.

PG&E's opening brief also criticizes the DRA methodology for relying upon just one year of data:

> "To make a long term projection, more than one year's change must be considered. DRA's use of a one-year change can in no

17 Similarly, DRA's opening brief advances arguments based on information, such as "PG&E deficiencies," which are not in the record. Because these facts are not in evidence, we give them no weight.

> way be called a trend analysis." (PG&E opening brief, p. 159.)

This criticism misses the mark. DRA's testimony does not purport to be a trend analysis. Instead, it is premised on the assumption that the estimates of premiums and accrual rates which are made prior to 1989 are likely to closely approximate the actual medical expenses to be incurred. Historically, the premium and accrual rates have proven to be within 1 to 4% of actual expenses. In particular, neither PG&E's rebuttal testimony nor its briefs explain why DRA's medical cost factor for 1989, based on 1989 premiums and accrual rates, will not accurately reflect 1989 medical expenses.

<u>Discussion</u>

Despite the limitations in both DRA's and PG&E's analyses and the failure of both parties to properly document their analyses, the task of developing a reasonably accurate estimate of 1990 expenses is not difficult.

For 1988, we agree with DRA that it is preferable to utilize actual recorded medical expenses, rather than PG&E's estimate of such expenses. The total company number we adopt for 1988 ($98,516,000) is slightly higher than PG&E's estimate for 1988 ($96,753,000).

For 1989, we agree with DRA that the premium and accrual rates for PG&E's HMO and indemnity plans are likely to be a very accurate estimate of expenses to be incurred in 1989. Therefore, we adopt an estimate of 1989 medical expenses 7% above 1988, at $105,412,000.

For 1990, we are not comfortable in assuming that premiums or costs in 1990 will match 1989. The increases in recorded medical expenses have varied widely between 1983 and 1988. Instead, we will adopt an estimate based on PG&E's actual historical costs. "The true comparison [of such costs]" according to PG&E's reply brief, "would be calculation of a percentage increase from year to year of total claims, premiums (HMOs), and administrative fees paid. A simple arithmetic average of the percentage increases in indemnity plan costs over the last 4 years shows a 9.2 percent increase...These numbers are further confirmed by an arithmetic average in the percentage increases in overall medical expenses of 9.5 percent." (PG&E reply brief, p. 35.)

We will therefore adopt an estimate of medical expenses in 1990 which is 9.5% above the 1989 estimate, at $115,426,000. We will not adopt the adjustment for "current medical cost factors" proposed by PG&E because PG&E has simply not met its burden of proof of explaining how these factors were derived and why they are not reflected in current trends.

We note PG&E's argument that "studies performed by recognized national experts such as Hewitt and Associates support the appropriateness of considering emerging issues in developing PG&E's trend factor." (PG&E reply brief, p. 35.) In support of this proposition, PG&E cites Exhibit 31, which is a one-page excerpt from the Medical Economic Digest issue of November 30, 1988. This page contains a pie-chart which describes factors expected to contribute to an increase in medical benefit costs in 1989. The chart indicates, for example, that medical inflation is expected to increase 7.1% in 1989, and represents 32% of the total increase in costs in 1989. While Exhibit 31 does indeed show that it is important to consider a variety of factors in estimating increased costs, it does not demonstrate the extent to which these factors are reflected in historical trends.

Finally, we consider DRA's request that PG&E be ordered to restructure its company/employee contribution policy and programs to compel employees to take more responsibility for the risks associated with their choices of medical care provider and lifestyle. DRA believes that PG&E's current contribution arrangement creates economic disincentives for risk sharing, discourages employees from choosing the plans that are the least expensive, and is unfair to PG&E retirees and ratepayers.

PG&E and the Unions object to DRA's recommendations. PG&E believes that DRA's proposal interferes with the collective bargaining process and ignores efforts already underway at PG&E. The Unions argue that DRA's proposal does not warrant serious attention:

> "Not only is the proposal maximally intrusive on collective bargaining, it is without arguable merit standing on its own. The proposal is not based on an analysis of the existing negotiated company contributions for PG&E's union-represented employees' medical coverage, is not based upon a finding that PG&E's contributions are currently unreasonable, is not based upon any external references, and is not based upon logic or reason." (Unions' opening brief, p. 22.)

We agree with PG&E and the Unions that DRA has not met its burden of proof in support of its request that the Commission order specific reforms in PG&E's medical plans. As the Unions point out, DRA's witness has testified that the amount paid by PG&E for Blue Cross coverage is reasonable and fair at this time, that the amounts established in the schedule of usual and customary charges are not unreasonable, and DRA has not concluded that PG&E's indemnity plan is overutilized. Given these circumstances, DRA has failed to demonstrate the need for the Commission to order specific reforms. By rejecting DRA's proposal we do not mean to imply that there is no room for further improvement in PG&E's medical programs; nor do we intend to suggest that, under future agreements, PG&E might not bargain for employee contribution to particular plans. We simply hold that DRA has not demonstrated why specific reforms are required at this time.

(4) <u>PSEA</u>

The Pacific Service Employees Association is a non-profit association open to all PG&E employees and retirees. There are currently 24,521 active employee members and 8,723 retired members. The purpose of the association, according to PG&E, is to foster a sense of fraternity and advance the interests of its members through charitable, educational, social, and recreational activities. PG&E contributes approximately 16% of PSEA's budget. PG&E requests a total of $422,000 ($295,000 electric, $127,000 gas) for its contribution to PSEA in 1990.

In D.67369, relating to the rates of Pacific Telephone, we stated that Pacific Telephone "hereby is placed on notice that it shall be the policy of this Commission henceforth to exclude from operating expenses for rate fixing purposes all amounts claimed for dues, donations, and contributions." (Emphasis added.) The California Supreme Court, upon review of our decision, found that this policy states the correct rule, and is in accord with the approach adopted in certain other jurisdictions. The court explained:

> "It may be emphasized that the commission's declared future policy does not purport to prohibit the utility from making contributions but only precludes charging them against its ratepayers. Further, we have no doubt of the importance of the contributions to the donees, as so eloquently expressed by able counsel appearing in their behalf, or that the funds so received will be devoted to beneficial uses. However, we hold that the policy adopted by the commission to exclude such contributions from operating expenses for rate-fixing purposes is correct." (Pacific Tel. Co. v. Public Utilities Comm., 62 C.2d 634, 669 (1965).)

DRA believes that the entire PSEA contribution should be disallowed, pursuant to the policy affirmed in the Pacific Telephone case.

PG&E believes that the Pacific Telephone case does not apply to PSEA. PG&E argues that the activities of PSEA do not fall into the four broad categories discussed in the Pacific Telephone case. In that case, the court notes Pacific Telephone's statement that its payments fall into four broad categories. But the policy announced by the Commission and upheld by the court was not limited to these categories. Instead, we announced our intent to exclude all amounts claimed for dues, donations and contributions, including but not limited to contributions to cultural organizations or service clubs.

Although PG&E's contribution is in the nature of a charitable contribution to an association for the furtherance of charitable, educational, and social activities, PG&E argues that certain of the functions relate to PG&E's operations and relate to the administration of employee benefits. This may be true and PG&E's contribution, if properly limited to these particular functions, may be a reasonable cost of service. However, PG&E has not offered testimony on how its contribution is directed, nor has PG&E quantified the costs which actually relate to PG&E operations. In the absence of such evidence, we agree with DRA that this expense must be disallowed.

f. Account 930.2: Other Miscellaneous General Expenses

The annual dues paid by PG&E to the Edison Electric Institute and American Gas Association[18] has been a matter of considerable controversy in past general rate cases.

In D.82-12-054 and D.82-12-055, we did not allow expenses for dues paid to EEI and AGA, because of the absence of a convincing showing that direct benefits of this expense accrue to ratepayers.

In its 1984 general rate case, PG&E presented detailed evidence in support of its position that the benefits derived by the ratepayer from utility membership in EEI justified the recovery

18 AGA dues are discussed in Section III, D.6.

of these dues as a reasonable cost of providing service. Based on testimony by an EEI witness, we concluded that PG&E's membership does produce some tangible benefits to ratepayers at a reasonable cost. We also noted testimony that more than 75% of EEI's budgeted activities support programs other than lobbying or Media Communications. Accordingly, we found it reasonable to allow ratepayer funding of 75% of PG&E's EEI dues. (D.83-12-068.) In subsequent general rate cases for other major electric and gas utilities, we have similarly concluded that only 75% of these dues should be recovered in rates. The 25% portion which we have disallowed, represents costs for advertising and lobbying which do not benefit ratepayers.

In its 1987 general rate case, PG&E did not provide the same level of detailed testimony as in the previous general rate case. Recognizing that efforts were underway by NARUC to develop a better understanding of EEI expenditures, we again authorized recovery of 75% of EEI dues pending completion of the NARUC study.

In 1988 NARUC completed an audit of EEI. According to PG&E, that audit showed 16% of EEI's expenses were for lobbying and might be disallowed for ratemaking purposes. Therefore, PG&E adjusted the 1988 EEI dues of $1,014,229 to remove $346,229 for advertising expenses, and then reduced this balance by 16% for lobbying expenses.

DRA also examined the NARUC audit. According to DRA, PG&E considered only those expenses identified by NARUC as "Legislative Advocacy." DRA believes that other categories of expenses should also be disallowed. The sum of these categories represents 20.46% of EEI's nonadvertising operating expense.

FEA witness Miller recommends excluding 25% of EEI dues. As Miller testified, in D.86-12-095 we stated that we would allow only 75% of EEI expenditures until the completion of NARUC's efforts to satisfy utility commissions as to the accountability of EEI expenditures. According to Miller, roughly 60% of EEI expenditures have not been broken out and NARUC is still attempting to obtain this detail. As a result, FEA recommends that we continue to allow only 75% of EEI dues.

PG&E, in its rebuttal testimony, described in greater detail the types of expenses which fall into each category questioned by DRA.

Although all parties rely upon the NARUC study as the basis of their recommendations, no party offered the study itself into evidence. Because we have previously indicated our intent to base our decisions on EEI dues upon the results of this study, on the Commission's own motion we will receive the "Audit Report on the Expenditures of the Edison Electric Institute (for the 12-month period ending December 31, 1987)" into evidence as Exhibit 400.

The NARUC audit divides EEI expenditures into twelve categories. One of these categories is "Legislative Advocacy." PG&E states that this category captures all lobbying costs and has therefore reduced EEI dues by 16%. DRA believes that six other categories also include lobbying expenses and therefore recommends a 20.46% reduction. We will examine these categories.

> <u>Legislative Policy Research</u>: PG&E describes this category as including expenditures on research or the preparation of background material not intended to influence proposed legislation. While it is possible that this account could include research not intended to influence legislation, the account is not defined in this manner. In fact, the account is defined to include general expenses associated with the general support of legislative advocacy. The account also includes all expenditures of a general political nature, such as grass roots organizing, if such activities are not related to a given piece of legislation. As defined by NARUC, this category clearly includes general costs of lobbying.
>
> <u>Regulatory Advocacy</u>: PG&E describes EEI's activities under this category as not tied to the actual rulemaking process, but intended to

support the development of reasonable and effective regulatory policies. Again, the NARUC definition of this expense category does not limit the account in the manner described by PG&E. Instead, NARUC defines the category as including expenses intended to influence regulatory actions, i.e. lobbying expenses:

> "Regulatory Advocacy - The cost of all written and oral communications with Federal or State regulatory agencies intended to influence the actions of such agencies and the cost of other expenditures which contribute in a general manner to furthering an EEI position on a regulatory or administrative matter."

Regulatory Policy Research: This category includes the costs of filing comments on proposed regulatory actions. Here, PG&E argues that EEI's involvement in regulatory proceedings may be beneficial to ratepayers. PG&E cites, as an example, EEI's 1989 comments to the Department of Interior on steam royalties from geothermal resources. However, PG&E has not provided us with evidence that EEI's regulatory research and advocacy, as a whole, is beneficial to ratepayers.

Contributions and Club Dues: PG&E states that these expenses were incurred consistent with the overall mission of EEI. Whether or not such expenses are consistent with EEI's overall mission, they are not consistent with our longstanding policy that ratepayers should not fund discretionary contributions to organizations when they have no voice in selecting the recipients. (D.86-01-026, mimeo. p. 74.) We note that EEI contributions in 1987 include contributions to political organizations such as the Democratic Leadership Council and the Republican Governors' Association. Such contributions, whether made directly by PG&E or indirectly through EEI, are not a reasonable cost of service.

In summary, we believe that the NARUC audit provides us with sufficient information to make an informed evaluation of the expenses which are appropriate for rate recovery. We will adopt DRA's proposed disallowance of EEI dues.

DRA also reviewed PG&E's list of indirect subscriptions and dues expenses. DRA proposes removal of all fees associated with organizations which provide no "quantifiable benefit" for the ratepayer or no information directly related to utility business. DRA believes that five organizations fall into this category, for a total reduction of $28,300.

PG&E responds, in its rebuttal testimony, that membership in each of these organizations serves a legitimate business purpose. That may be so, but it is not the standard by which we judge whether dues represent a legitimate cost of service. Instead, the issue before us is whether the membership will accrue direct benefits to ratepayers. Such benefits need not always be quantifiable, but they must be tangible. For example, PG&E describes Northern California Grantmakers as a regional association of foundations and corporations with philanthropic programs. PG&E is a corporation with philanthropic programs, but such programs are not funded by ratepayers. PG&E has failed to explain the benefit to ratepayers of PG&E's membership in this group. The benefits to ratepayers from PG&E's participation in the other organizations identified by DRA are similarly unexplained.

As a result of adopting DRA's recommendations regarding EEI and other membership dues, we will reduce PG&E's request by $49,000.

g. <u>Account 931: Rents</u>

DRA accepts PG&E estimates of lease costs in 1990, but because these costs are expected to decline in 1991 and 1992, DRA proposes that we average lease costs over a three-year period, from 1990 to 1992. The anticipated decrease in leased space in 1991 and 1992 results from PG&E's continued effort to consolidate working groups and use office space more efficiently. This is the type of improved efficiency we expect to see during the attrition years;

these savings should help to offset other increased costs not authorized in the test year. DRA's proposal to average these lease costs is denied.

6. Electric Plant and Rate Base

a. Abandoned Plant

PG&E orginally requested $14,947,000 for amortization of a number of abandoned projects over a four year period. The projects requested to be amortized are set forth in Exhibit 102.

DRA recommended that PG&E be allowed to amortize all of the projects except Geysers 21 and 22. PG&E is currently suing UNOCAL to recover the costs of these projects. DRA believes that PG&E should be able to recover a substantial portion of the costs of Geysers 21 and 22. DRA recommends that the Commission wait for the outcome of the litigation before deciding whether to amortize these projects.

PG&E accepts DRA's recommendation regarding amortization of Geysers 21 and 22. PG&E has reduced its request for amortization to $3,968,000.

PG&E asserts that the abandoned projects in its revised request meet the Commissions's criteria for recovery. As set forth in D.83-12-068, as modified in D.84-05-100, our policy of rate recovery for abandoned projects provides for a sharing of costs between ratepayers and shareholders during periods of great uncertainty. The general rule of ratemaking has been that a utility is not allowed to recover the costs of plant which is not used or useful. But we have created an exception during periods of great uncertainty:

> "The exception is the product of the period of dramatic and unanticipated change, initiated most notably for utility planners by the oil embargo of 1973, and extending for almost a decade. The period was characterized by great uncertainty in the energy industry, both as to demand growth and availability of supply. During such a period, a reasonable utility management can still reduce risk, but not

> necessarily to a level at which the shareholder may fairly be expected to absorb all the costs of cancelled projects. During such a period, the ratepayer should participate in the increased risk confronting the utility.
>
> "But the ratepayer does not become the utility's underwriter in a period of high risk. At all times, the shareholder will bear some of the risks of abandoned projects. The utility should bear a major part of the risk in order to provide proper management incentives. Also, the ratepayer's participation is limited to those abandoned projects, or those portions of projects, for which the utility demonstrates to us that it has exercised reasonable managerial skill. We emphasize that the utility bears the burden of proof of reasonableness, not only with respect to the planning and conduct of a given project, but also regarding the cancellation, which must have occurred promptly when conditions warranted. Finally, a perception merely of generalized and ill-defined risk will not suffice to invoke this exception to the 'used and useful' principles. The utility will have to demonstrate that the project which it ultimately abandoned was reasonable throughout the project's duration in light both of the relevant uncertainties that then existed and of the alternatives for meeting the service needs of its customers.
>
> "Thus, although we will occasionally relax the 'used and useful' principles with respect to cancelled projects, we will continue to rigorously apply the criterion of reasonable managerial skill to costs deriving from such projects, as indeed we apply this criterion to all utility expenditures." (D.84-05-100, mimeo. pp. 3-4.)

In D.83-12-068, as modified by D.84-05-100, we held that 24 projects met these criteria. One project, the Mendocino Nuclear Project, did not qualify. It was cancelled not because of supply uncertainty, but because the proposed site was geologically unsuitable.

PG&E, in its present application has not met its burden of showing that these abandoned projects satisfy the criteria established in D.83-12-068. Exhibit 6, PG&E's direct filed testimony, contains merely a listing of the projects. It did not specifically address any of the considerations enumerated in D.83-12-068.

When PG&E witness Forsgard testified regarding this revenue request, ALJ Wheatland stated that "as I consider the request and the need to write a decision supporting the request, there are no facts that I could find in the testimony that would support the reasonableness or the prudence [or] to relate those projects to the criteria that you have stated. Are these set forth somewhere in the testimony that I have missed?" (Tr. 7:685.) In response, Forsgard indicated that PG&E's workpapers describing these projects are included in DRA's testimony, Exhibit 102.

Exhibit 102, which includes only a brief description of each abandoned project, does not satisfy PG&E's burden of proof. PG&E has not shown (1) that the project ran its course during a period of unusual and protracted uncertainty, (2) that the project was reasonable throughout the project's duration in light of both the relevant uncertainties that then existed and of the alternatives for meeting the service needs of the customers, (3) when the projects were cancelled, and (4) that they were cancelled promptly when conditions warranted.

The information which PG&E has provided suggests that many projects do <u>not</u> comply with our criteria. For example, the proposed expansion of the Angels Camp office was not cancelled because of any extraordinary uncertainties, but because staffing reductions made expansion unnecessary. Similarly, the Butte Canal Tunnel was cancelled not because of great supply uncertainty, but because ground conditions changed during the preliminary engineering phases. Another project, a service connection to a new 24-story office building in San Francisco, was cancelled when the developer of the project stopped construction of the building due to financial difficulties.

PG&E's request to amortize the costs of the Dinkey Creek Project is particularly troubling. In A.86-02-008, PG&E requested approval of an agreement it signed with the Kings River Conservation District to construct the Dinkey Creek Hydroelectric Project, and PG&E requested authorization to recover all payments under the agreement. We dismissed the application, without prejudice, indicating that we simply did not have enough information to find that ratepayers would be indifferent. On October 27, 1986, eleven days after our decision, PG&E cancelled the project. Under the terms of the agreement with the District, PG&E paid 50% of the design costs which had been incurred, $2.05 million. PG&E believes that the initial decision to pursue the project was prudent, based upon the cost/benefit analyses at the time. Yet, this was the very question tendered to us in A.86-02-008, and we indicated then that PG&E had not provided sufficient information to convince us that this was so. PG&E's general rate case application certainly adds no additional information to demonstrate that this project was ever prudent.

PG&E states that it abandoned the Dinkey Creek Project in a timely manner when information became available that it was no longer in the best interests of ratepayers to pursue the project. The information which became available, as far as we are able to ascertain from the information provided in Exhibit 77, had nothing to do with the interests of ratepayers. The information which cancelled the project was this Commission's determination that shareholders should bear the risk of project development. When we declined to give shareholders the assurance of full rate recovery, PG&E decided to cancel the agreement.

None of the reasons for canceling the aforementioned projects fall within the narrow exception to the "used and useful" rule of D.84-05-100. While we will occasionally relax the used and useful principles in a period of high risk, we remind PG&E that, as we stated in D.84-05-100, "the ratepayer does not become the utility's underwriter" for all cancelled projects.

In summary, we conclude that the record does not support a finding that the recently abandoned projects which PG&E proposes to amortize meet the criteria for cost recovery enunciated in D.83-12-068, as modified by D.84-05-100.

b. Electric Plant Held for Future Use

In D.87-12-066, Edison's last general rate case decision, we adopted specific guidelines to govern the length of time that items could be detained in PHFU:

> "PHFU is an area in which we do not have specific criteria for judging the reasonableness of a utility's property acquisition policies. Because of this, utilities do not have a strong incentive to closely monitor their procedures for acquiring and maintaining PHFU. ALJ Ferraro directed PSD and Edison to work together to develop guidelines which could be used to judge the reasonableness of utility expenditures on PHFU. As a result, PSD and Edison developed guidelines and agreed to their use in the future. We find these guidelines reasonable and will adopt them for use in this and Edison's future general rate cases. In addition, we will direct our Evaluation and Compliance Division to notify the energy utilities under our jurisdiction that we expect to adopt similar guidelines in their next general rate case." (D.87-12-066, mimeo, pp. 39-40.)

Despite our announced intent to adopt similar guidelines for other electric utilities, PG&E did not address this issue in its application. It did not do so, it says, because neither CACD nor DRA approached PG&E on this issue before the company filed its application. Thus, PG&E claims it did not have timely notice that the guidelines were to be an issue in this general rate case.

We do not accept PG&E's argument that it did not have timely notice that we intended to adopt similar guidelines in its next general rate case. Although CACD did not formally notify PG&E until February 2, 1989, PG&E was a party to Edison's general rate case and had actual notice of our decision.

The purpose of the guidelines, as set forth in Appendix L, is to balance the utility's natural desire for maximum possible flexibility in the planning and acquisition of future plant with the ratepayer's desire to avoid unnecessary or burdensome carrying costs of property which is held for an indefinite period or an indefinite purpose. PG&E agrees with the guidelines we adopted in D.87-12-066, except for one provision. The guidelines provide that right-of-way associated with transmission lines and substations be allowed to remain in PHFU for ten years if associated with new power plants, and in PHFU for five years if not associated with new power plants. PG&E sees no difference between these two types of land acquisition activities and believes that the guidelines should allow ten years for all right-of-ways. PG&E believes that ten years is simply not enough time to assemble a corridor of land for transmission purposes. PG&E also notes that General Order 131-C requires ten years of planning information prior to the construction of a transmission line. Given the ten-year planning horizon, PG&E believes it unfair to only allow ratemaking consideration of the property for five years before the line is to be operational.

We have carefully reviewed that portion of the guidelines to which PG&E objects. In most cases the planning, environmental review, and permitting process for power plants and related facilities is longer and more complex than that required for transmission lines alone. We believe it is reasonable therefore to provide a longer holding period for power plants and related transmission facilities than for transmission facilities only. We also remind PG&E that it is not required to plan the project, purchase the land, and build the line within five years. Much of the planning and environmental review should take place before acquisition begins. Moreover, once construction begins, the costs may be transferred to the construction budget and may remain in that budget up to five years. Thus, the maximum time a transmission right-of-way not related to a new power plant may be held in PHFU prior to the start of construction is ten years.

The five-year guideline affects one particular transmission line in PG&E's current PHFU account - the Gates to Gregg transmission line. In 1978 PG&E applied for a certificate authorizing it to construct a 51.5 mile 500 kV transmission line between the Gates substation to the proposed Gregg substation. After review of the application, we held in D.89852 (1 CPUC 2d 134) that there was inadequate information in the record of the proceeding to justify Commission approval of the project. Therefore, we denied the application and invited PG&E to file a new application containing information sufficient to correct the various deficiencies. That was in 1979. It is not until February 28, 1989, that PG&E indicated a planned operational date for this facility (January 1995). While we do not doubt the sincerity of PG&E's current testimony that there is now a definite plan to build this transmission line, PG&E made the same representations to us with equal conviction, ten years ago. In the case of this particular facility we believe that application of the PHFU guidelines is fully warranted.

The guidelines also affect two properties immediately adjacent to the Pittsburg power plant. Although PG&E has no specific plan for use of these parcels, PG&E believes that they should be retained in PHFU to provide for future expansion of the powerplant. In addition, PG&E states that these projects currently serve as an environmental buffer and are valuable in this function. Under the guidelines we adopt, exceptions to the maximum time periods may be granted where the utility satisfactorily establishes that (1) there is still a definite plan and need to retain the item in PHFU, (2) economic analysis justifies the retention and (3) there are mitigating circumstances to require the retention. In the case of the Pittsburg properties, PG&E has neither shown a definite plan and need, nor an economic analysis to justify retention. Under these circumstances, we deny PG&E's request for an exception from the guidelines.

As in D.87-12-066, we will adopt the guidelines prospectively. Effective January 1, 1991, we will apply the acquisition guidelines as if they were effective prior to the acquisition date of all items in PHFU. This will result in a reduction of $3,031,000 in PG&E's request for attrition year 1991. We will not make any adjustment in the test year. As we stated in D.87-12-066, by delaying full implementation of the guidelines the utility will have ample opportunity to manage its PHFU account to the level adopted in this decision. "We believe, by providing ratepayers with lower carrying charges now and in the future and shareholders with the opportunity to adjust to this change, the interests of ratepayers and shareholders are fairly balanced." (D.87-12-066, mimeo. p. 40.)

c. Common Plant

PG&E and DRA differ on the allocation of common plant for two reasons: (1) PG&E and DRA have different estimates of the amount of common plant to be allocated to Diablo Canyon, and (2) DRA opposes the inclusion of two specific projects in the estimate of 1990 common plant additions.

(1) Allocation of Common Plant to Diablo Canyon

As described earlier in this decision, D.88-12-083 requires that all Diablo Canyon operations shall be segregated from other PG&E operations. Diablo Canyon costs include all costs incurred by PG&E as a result of Diablo Canyon ownership. Diablo Canyon costs include "common costs." The term "common costs" is not described in D.88-12-083. Instead, that decision states that the detailed methodology for allocation of common costs will be described and determined in the PG&E general rate case.

With rare exceptions, the Commission has used either direct use studies or the four-factor method to allocate plant which is common to two or more departments among the various departments. PG&E uses the four-factor method in this proceeding to allocate common plant among the electric, gas, and steam department.

Although the costs of operating and maintaining Diablo Canyon are now to be segregated from other PG&E operations, PG&E has not allocated common plant to Diablo Canyon using the four-factor method. PG&E has removed from rate base $134,000,000 of plant within the gates of the Diablo Canyon facility and used by Diablo Canyon, which according to PG&E would ordinarily be classified as as "common plant" or would normally have been built in common with other parts of PG&E's system.[19] PG&E did not remove from rate base and allocate to Diablo Canyon any common plant outside the gates of Diablo Canyon. Instead, as this proceeding progressed, PG&E surveyed common plant outside the gates of Diablo Canyon and began to identify common plant which is shared by Diablo Canyon. The results of PG&E's review were presented in Exhibit 33. PG&E identified $5,000,000 in Diablo related expense, reflecting charges and rentals attributable to the use by Diablo Canyon employees of vehicles, aircraft, and the General Office complex.

19 DRA questions whether the plant allocated to Diablo Canyon would otherwise be properly classified as "common plant." PG&E defines common plant as plant consists chiefly of plant that is used by several departments of the company. PG&E has not demonstrated that the $43 million in "common plant" allocated to Diablo is used by other departments. In fact, PG&E's testimony suggests that some of the costs are clearly not common. (Tr. 50/5417-17, 5432-35.)

The chargeback system initially described by PG&E did not fully reflect the costs of Diablo Canyon. The user fees for vehicles and aircraft reflected the cost of depreciation, but not return or taxes. Fees for the warehouse and training center did not reflect fully allocated costs. No fees were charged for Diablo Canyon's use of the Fairfield computer center. In rebuttal testimony, PG&E proposed revisions to these charging policies, and indicated its intent to establish a computer use billing system.

DRA believes that PG&E's allocation of common plant to Diablo Canyon significantly understates the cost of common plant shared between PG&E and other departments. Therefore, to allocate common costs between Diablo Canyon and other departments, DRA developed the following approach. First, the traditional four-factor method is used to allocate common plant between the electric, gas, and steam departments. Next, a special four-factor method is used to allocate common plant within the electric department between Diablo Canyon and the remainder of the electric department. Based on this approach, DRA initially concluded that $250 million in common plant should be allocated to Diablo Canyon.

PG&E strenuously criticizes DRA's new four-factor method as it was applied to both A&G expenses and common plant. PG&E's criticisms of the application of the special four-factor method to A&G expenses (See Section III.C.5.a, supra) are equally applicable here. In addition to the criticism previously described, PG&E particularly objected to certain aspects of the methodology when applied to common plant. PG&E offered testimony in Exhibit 58 to show that most of PG&E's $1.3 billion in common plant has no functional or geographical relationship to Diablo Canyon, such as laboratories, training facilities, gas terminals, compressor stations, powerhouses, and customer service centers.

After reviewing Exhibit 58, DRA reduced the common plant to which it would apply its special four-factor method to three categories of facilities and equipment outside the gates of Diablo

Canyon--Computer Centers and Telecommunication Equipment, Transportation Equipment, and the General Office Complex. This reduced DRA's proposed allocation of common plant to Diablo Canyon to $151,200,000. The revenue requirement for DRA's allocation of common plant to Diablo Canyon is $22,027,000, which exceeds PG&E's estimate of total plant charges by $19,203,000.

Discussion

Neither DRA nor PG&E has advanced an acceptable method for fairly and accurately allocating the costs of plant shared between Diablo Canyon and other departments of PG&E.

DRA's method is likely to overstate the costs of common plant attributable to Diablo Canyon. As we explained earlier in this decision, the use of gross plant cost as a special factor will tend to overstate Diablo Canyon's share of common plant. Newer generating facilities cost more than older generating units. Yet the relative age or cost of two facilities bears no rational relationship to the allocation of plant which is common to the two units. In addition, we also find that the use of annual energy output will distort the results in periods of low operation. We find that DRA's special four-factor would produce distorted and unreasonable results when used to allocate common plant to Diablo Canyon.

On the other hand, PG&E's proposed charge of $5,000,000 is likely to understate the costs incurred by Diablo Canyon for the use of shared facilities outside the gates of Diablo Canyon. Because the decision adopting the Diablo Canyon settlement was issued in December 1988, at about the time PG&E filed its general rate case application, PG&E is only now in the process of identifying common plant outside the gates of Diablo Canyon which is shared by Diablo Canyon. While PG&E is dedicated to developing a system for directly charging all common plant used by Diablo Canyon, that process is not yet fully implemented.

To ensure that the system which PG&E implements will fully and fairly allocate all common plant used by Diablo Canyon, we will direct PG&E to conduct a facility-by-facility use study of all common plant. This study shall be conducted in conjunction with the use study which PG&E will conduct for A&G expenses. The costs of developing the direct charge system, reviewing all common facilities, and filing the report shall be charged to Diablo Canyon.

After PG&E has conducted a complete use study of common plant and has fully implemented its system of direct charging we would expect PG&E to directly charge considerably more than $5,000,000 annually to Diablo Canyon for its use of common plant outside the gates of the facility. However, given the fact that neither DRA or PG&E have fully reviewed all common plant outside the gates of Diablo Canyon, there is not a basis on this record for a further adjustment at this time. We will not adopt DRA's additional disallowance of $19,203,000.

(2) <u>Common Plant Additions</u>

Two of the projects included in PG&E's estimate of common plant additions are the (1) San Francisco Division Consolidation Project and (2) Emeryville Transformer Repair Center. DRA does not include these projects in its estimate of 1990 common plant additions.

In PG&E's application, these projects are shown as becoming operational in 1991 and 1992. PG&E subsequently informed DRA that the San Francisco project was included in the attrition years, rather than the test year, in error. The Emeryville project represents a change in priorities resulting from increased interest by the City of Emeryville in this project.

DRA's brief states that DRA opposes these projects because the Rate Case Plan precludes changes in any of PG&E's estimates after the filing of the application, citing the testimony of DRA witness Han at Tr. 14:1438. Yet, as PG&E notes, on the next page of the transcript Han appears to agree that it is reasonable to take into account changes in the schedules of projects listed in the application which may be moved between the test year and attrition years. (Tr. 14:1349.)

While we are sympathetic to DRA's need to have adequate time to review the application, in this instance we believe PG&E has provided DRA adequate time to review these projects and that PG&E has demonstrated that both projects will be used and useful in 1990. We will approve PG&E's estimate of 1990 common plant additions.

7. Depreciation

DRA and PG&E agree on the methodology for calculating depreciation and depreciation reserve. The difference between PG&E and DRA for electric department depreciation expense is due to differences in determining common utility plant additions, allocation of Diablo Canyon costs, and four-factors.

8. Taxes

DRA and PG&E also agree on the methodology for calculating income, payroll, property, and other tax expense. The differences between DRA and PG&E are due to differences in other revenue and expense estimates.

9. Nuclear Decommissioning

PG&E proposes that decommissioning rates be maintained at currently authorized levels until termination of the funding for the Humboldt Bay Unit 3 plant, and until the next general rate case proceeding for the Diablo Canyon Power Plant. Energy and Resource Advocates (ERA) proposes increasing the Humboldt decommissioning factor from 25% to 50%. DRA proposes that decommissioning expense levels for Diablo Canyon and Humboldt be decreased by $7,231,000, based on PG&E's updated expense forecast.

Regarding the Humboldt plant, we note that the Humboldt decommissioning fund will be fully collected at present rates by 1991, and the expense will thereafter be removed from rates. ERA has not offered a persuasive case for increasing the decommissioning factor for the remaining period that the rate will be in effect. PG&E's Humboldt decommissioning cost estimates indicate that the anticipated decommissioning expenses are likely to be less than the amounts accrued at a 25% factor.

Nor do we agree with DRA that we should reduce the annual accrual rate for Humboldt. As DRA acknowledges, there will be adequate future opportunity to adjust PG&E's revenues if we subsequently find Humboldt expenses to be overcollected.

For the Diablo Canyon plant, in D.87-03-029 we authorized collection of annual revenue for decommissioning of $54,474,000 beginning March 16, 1987. This rate was based upon an estimate of decommissioning costs prepared in 1986 and our best estimate in 1987 of the rate of return on invested funds and the escalation rate of future costs.

In August 1988 PG&E completed an updated review of decommissioning costs. DRA reviewed this study and found that the cost estimates are reasonable and well supported. DRA also believes that the escalation rates and investment rates used by PG&E are reasonable.

Based on PG&E's most recent estimate of the costs of decommissioning Diablo Canyon, PG&E would need to collect $52,015,000 annually, beginning in 1990. This is $2,459,000 less than PG&E is currently collecting. DRA believes that the Commission should use this lower, more recent cost estimate in establishing PG&E's expenses in the test year.

PG&E, on the other hand, argues that the difference between the regular accrual rates and the 1988 forecasted rate is relatively insignificant. Current rates are within 4-6% of the best current estimate. Given the ultimate uncertainty of decommissioning costs, PG&E believes it is sufficient to keep funding within a range of reasonable costs.

DRA acknowledges the uncertainty in determining ultimate costs, but believes that the Commission should use the best information to readjust the accrual rate in each case, understanding the information is not perfect.

At this time, there are significant future uncertainties concerning the timing of decommissioning and the amount ultimately necessary to complete the work. There is also much uncertainty regarding the rate at which the trust will appreciate over the next three decades. Given the range of future uncertainty, minor fluctuations between the authorized accrual rates and the most recently forecasted rate of accrual are not a matter of immediate concern. A difference of 4-6%, as in this case, is within the margin of error of the forecast, and well within a reasonable range at the outset of a 30-year accrual period. DRA's adjustment would impose a level of precision which is not necessary at this time.

Accordingly, we will continue the current accrual rates for Humboldt and Diablo Canyon.

10. <u>Working Cash</u>

The revenue requirement adopted in this decision does not reflect D.89-11-058 related to the change to flow-through for the California Corporate Franchise Tax (CCFT) deduction in estimating ratemaking federal income tax expense. Therefore, no later than October 1, 1990, PG&E shall file an Advice Letter to true-up test year 1990 ratemaking federal income tax expense. The resulting difference in revenue requirement shall be included in PG&E's 1991 attrition increase.

We accept PG&E's contention that the DRA adjustment to Economic Recovery Tax Act of 1981 (ERTA) tax basis should also be included in the decision on test year 1990.

11. <u>Jurisdictional Allocation</u>

DRA and PG&E agree on the methodology for allocation of costs and revenues between state and federal jurisdictions. In particular, DRA and PG&E agree that both the costs and revenues associated with discounted sales by PG&E to FERC jurisdictional customers be included in the CPUC jurisdiction to ratemaking. At DRA's suggestion, we will require that in future general rate cases PG&E provide a cost/benefit study for each discounted sale to be included in CPUC jurisdiction during the test year.

DRA also proposes that PG&E be required to provide a cost/benefit analysis of the Sacramento Municipal Utility District (SMUD) sale in each ECAC proceeding. PG&E responds that updating the cost-benefit analysis of a ten-year contract every year makes little sense. PG&E believes that a three-year review provides sufficient opportunity for the Commission to assess the economics of this contract.

DRA's analysis shows that in nearly all cases the ratepayers will benefit from PG&E's sale to SMUD. The only scenario in which there is the possibility of a negative contribution from the sale assumes a 1,000 MW purchase by SMUD at the same time PG&E needs the 1,000 MW. Our evaluation of PG&E's resource plan indicates that it is highly unlikely PG&E will need the full 1,000 MW itself within the next three years. Therefore, we see no need for annual review of the costs and benefits of the SMUD contract prior to the next general rate case.

12. <u>DRA's Proposed Adjustments</u>

a. <u>Compensation</u>

DRA's Exhibit 107 provides a short, somewhat sketchy description of the methodology used by DRA to evaluate PG&E salaries:

"(1) The survey for setting the standard market rates should not be more than two years old.

(2) Benchmark positions should be included in each survey. Benchmark positions are the positions that PG&E uses for comparison purposes with other utility companies and with other industries. Also, benchmark positions are significant because of their importance to the operations of the

utility and they usually employ many of the company's workers in a single occupational category.

(3) PG&E compensation professionals were responsible for the job matches.

(4) Surveys were chosen from utility-related large organizations and from national and local data sources.

(5) An aging factor was used to update the survey data to the PG&E data. An aging factor is an index which is applied to the survey data to escalate prior year's survey's compensation levels to PG&E's June 1988 compensation levels...."

"The following steps were taken to develop the analysis:

Step 1 - After the data base was established, DRA used the average of the survey means of the wages and salaries and compared those with PG&E's means of the wages and salaries in the five categories.

Step 2 - DRA weighted PG&E mean wages and salaries and survey mean wages and salaries by PG&E's number of employees in each of the classifications and in each of the categories.

Step 3 - DRA summed up the total weighted wages and salaries of PG&E and the proprietary surveys for each category.

Step 4 - DRA evaluated the result of the study from the percentage differences observed in Step 3 in the five categories." (Exh. 107, pp. 2-3.)

DRA recommends that PG&E's labor expense be reduced by $30 million in the test year. DRA believes that PG&E's wage and salary levels are 6.64% over the market rates.[20] DRA believes that the clerical workforce is significantly overpaid. DRA argues that the company's benefits, training opportunities, and relative job security are ample enough to maintain qualified and productive clerical employees, without also paying 18% over market rates.

PG&E did not present a salary survey in this proceeding. PG&E viewed its role as being responsive to DRA data requests and providing technical assistance to the DRA as required. PG&E provided DRA with abstracts of various salary surveys and furnished technical assistance to DRA on data interpretation. PG&E believes that:

> "The survey data used by the DRA are generally representative of PG&E's external labor market. Furthermore, the methodology applied by the DRA to analyze the data for each employee group appears to be reasonably sound. However, several significant oversights in their interpretation of the survey results caused the DRA's conclusion to be invalid. Specifically, the DRA's conclusion to recommend a disallowance ignores the very real influences that survey response ranges, survey error, and employee tenure have on the interpretation of survey results. In addition, the DRA's conclusion does not recognize efficiency wage theory, even though it was discussed by PG&E and recognized by the Commission in the 1987 GRC decision." (Exhibit 64, pp. 3B-13, 14.)

20 DRA's compensation study is summarized as follows:

Category	PG&E Over/Under Market	Weighted By Payroll	Impact
Clerical	19.10%	15.06%	2.88%
Physical	7.99%	44.80%	3.58%
Technical	5.47%	6.16%	0.34%
Professional	-0.29%	33.48%	-0.10%
Executive	-4.85%	0.50%	-0.02%
Total		100.00%	6.68%

In its rebuttal testimony, PG&E explained how it would interpret DRA results differently. First, PG&E determined that responses to survey questions average 9.36% across the surveys used by DRA:

> "From this calculation it can be concluded that the band of competitiveness in pay operating within the DRA's survey is plus or minus 9.36 percent. Simply stated, pay that is within the range of plus or minus 9.36 percent of the DRA's salary survey results must be considered competitive and reasonable." (Exhibit 64, pp. 3B-14.)

PG&E also identified several other survey factors which it believes diminish the certainty of DRA's conclusions. According to PG&E, DRA did not consider the high tenure of PG&E employees, nor the benefits of efficiency realized from paying employees above the market rate.

In its opening brief, PG&E compares the average clerical wage of SoCal Gas ($14.52/hr and 6.75% above market) and of PG&E ($14.21/hr. and 18.42% above market) and asks if it is plausible that PG&E's average clerical salary can be lower than SoCal Gas' average clerical salary and yet have a higher variance from market rates.

The Unions also offered testimony on the question of compensation. Joseph Grodin testified regarding national labor policy, the dynamics of collective bargaining and the role of the state in collective bargaining under national labor policy. Jonathan Leonard testified regarding certain systematic problems associated with using the clerical job market as the measure for appropriate wage levels for PG&E clerical employees. Ben Hudnall and Jack McNally described collective bargaining at PG&E and provided various comments on the DRA survey. Eugene Hamilton and William T. Dickens testified regarding weaknesses in the methodology used by DRA in its wage survey. Jeffrie Van Hook and

Debbi Mazzanti testified regarding their role as Service Representatives at PG&E.

According to the Unions, the DRA methodology is seriously deficient in (1) the use of surveys representing incorrect labor markets, (2) not having access to or understanding the surveys it used, and (3) improperly matching at least five key positions covering a large number of employees.

The Unions also assert that DRA failed to properly apply informed judgment to the data which it selected: (1) using a simple average of survey results, rather than an average weighted to the number of incumbents in each survey, (2) failing to estimate either the standard error of the individual surveys or the standard error resulting from the combined surveys, (3) failing to focus on the benchmark classifications, (4) relying on a large number of positions matched only to one survey, and (5) failing to use interquartile data for categories other than executives.

In addition to their critique of DRA's survey methodology, the Unions offered testimony on policy issues relating to the interpretation of DRA's survey. Even assuming that PG&E employees are paid more than the relevant job market, an assumption the Unions strongly contest, they believe no additional adjustment should be made because, among other reasons, (1) collective bargaining takes place as a package, and to isolate the wage element of the package ignores other parts of the bargain, (2) unionized firms tend to pay more than non-union firms, (3) use of external wage surveys to evaluate salaries of predominantly female jobs would import sex discrimination to the PG&E workplace, and (4) PG&E employees, particularly its clerical employees are highly tenured and extremely productive.

<u>Discussion</u>

Prior to the last general rate case, we typically authorized wages and salaries by simply escalating current salary rates by an escalation factor. However, in D.83-12-068, we expressed our concern

> "...that the process of escalating wage and salary levels by a certain escalation factor (often the actual wage increase negotiated by PG&E and the union is used for this process), can result in significant increases in the overall level of wages and salaries through the years without any review by the Commission as to whether or not the salaries and wages paid are in fact reasonable when compared to wages and salaries in the marketplace for similar types of work.
>
> "The staff has concluded that examination of the reasonableness of wage and salary levels can be accomplished within the context of a general rate case proceedings. PG&E already performs comparable wage studies based on west coast and regional wage comparisons. Inasmuch as these studies have to be prepared every year for PG&E to participate in wage and salary negotiations with the unions that represent its employees, these studies are available on a current basis for presentation in Commission proceedings.
>
> "We will expect in PG&E's next general rate case proceeding a presentation of levels of wages and salaries estimated by the utility for comparison with similar wages and salaries paid in the marketplace. This will be a check upon the routine procedure in general rate cases of simply escalating all salaries by a certain labor escalation factor. In this way, it will be possible on a more specific basis to see if the amounts allowed as labor increases in the past have in fact resulted in reasonable levels of wages and salaries being provided to PG&E employees. It also provides the opportunity to see whether or not such overall escalation has resulted in excessive increases in any particular wage or salary category where comparable salaries in the marketplace have not risen at the same rate." (D.83-12-068, pp. 29-30.)

In compliance with our direction, both PG&E and DRA submitted salary comparisons in the following general rate case.

After careful consideration, we decided not to adopt the results of the DRA study, because the study was weak with regard to proper matching of key positions, the study relied on one survey source with a high sampling error (14% at 95% confidence level) and because the study did not focus on the labor market from which PG&E must draw for its labor.

We chose instead to rely upon the PG&E salary survey for evaluation of salaries and wages. According to PG&E, the wages and salaries for physical employees were 6.7% above market average, salaries for technical employees were 2.7% above market average, and clerical employee salaries were 13.6% above market average. Although we did not determine the sampling error of the PG&E survey, we noted PG&E's testimony that generally placed sampling error in the range of 10%. Bearing in mind the probability of some sampling error in the PG&E salary survey, we concluded that PG&E's salaries for technical and physical employees are not excessive to the point where a ratemaking adjustment should be made. In addition, we found that a small premium in salaries above market rates can benefit the ratepayers and stockholders, by safeguarding PG&E's large investment in employee training. PG&E's survey indicated that clerical employees were paid 13.6% above market rates. We concluded that this estimate was not unreasonable for the 1987 test year, taking into account the sampling error and the internal equities. (D.86-12-095, mimeo. p. 53.)

The following year, in Edison's general rate case, we again considered the question of compensation. We found that DRA's analysis in Edison's general rate case proceeding was a significant improvement over its analysis in the PG&E general rate case:

> "However, before it can be used to judge the reasonableness of Edison's level of payroll expenses, there are further refinements that should be considered. First, comparisons should either be made on a total compensation basis or adjusted to reflect the employees' benefit package. Since employees choose employment opportunities on a total

> compensation basis, we consider it reasonable to judge utility compensation in the same manner. Second, in addition to point comparisons based on averages, information indicating the range of data should be provided. Lastly, Edison's criticisms concerning sample sizes and the duplication of jobs and companies in the survey data should be addressed." (D.87-12-066, mimeo. p. 103.)

We turn now to the salary survey presented by DRA in this proceeding. DRA's current survey is disappointing. As the Unions correctly note, this DRA salary survey suffers some of the same errors and limitations as noted by the Commission in the 1987 general rate case. Once again DRA's survey is weak with regard to the proper matching of key positions which cover a large number of employees. Additionally, we agree with PG&E and the Unions that it is necessary to determine the standard error of the surveys and to take this range of error into account in evaluating the results.

DRA's survey in this case also fails to contain the further refinements we requested in D.87-12-066. DRA's survey does not make a comparison on a total compensation basis. Furthermore, DRA continues to provide point comparisons based on averages, without also indicating the range of data. Finally, we had asked staff in future surveys to address Edison's concerns regarding the overlap between companies in several surveys. Yet, in this case, DRA was even less aware of which companies participated in the surveys it used.

For these reasons we cannot adopt DRA's salary survey as the basis for an adjustment in PG&E employee compensation in 1990. We make this determination based on the methodological flaws in the survey and the absence of necessary refinements. We do not decide the question based on the policy issues proffered by PG&E and the Unions.

While we are disappointed in DRA's showing, we are even more disappointed in PG&E's showing on this issue in this proceeding. The burden of proof on the reasonableness of compensation is on the utility, not the staff. We have tried to make it clear in D.83-12-068, D.86-12-095, and D.87-12-066, that we expect the utility to do more that simply critique DRA's efforts. We expect an affirmative presentation from the utility on the level of overall compensation and a comparison to similar compensation levels in the relevant job markets. In the absence of such a showing from the utility we are reluctant to apply any labor escalation factor to wage levels found reasonable in the previous general rate proceeding.

We will stress, as we have before, that while we have not adopted DRA's adjustment, we do not intend to give the utility a blank check. We expect PG&E to help us ensure that ratepayers are not burdened with employee compensation beyond that which is necessary to provide safe, reliable service at the lowest reasonable cost. As long as PG&E bargains aggressively and effectively on the ratepayers behalf, we will, as Grodin suggests, allow very substantial latitude to the judgment of management and the unions with respect to the specific nature of the bargain rather than attempt to fine tune it in accordance with our own notions of what would be ideal.

b. <u>Accounting System</u>

DRA performed an audit of the accounting and financial records of PG&E. DRA auditors report that they experienced significant difficulty in obtaining basic information from the PG&E accounting system. Among the specific difficulties reported were the following:

> "a. The inability to easily convert the PG&E accounting system to the FERC Uniform System of Accounts system. While PG&E submits formal reports to the Commission on a FERC basis, the audit process needs to be able to convert PG&E's accounts directly.
>
> "b. Translating PG&E account numbers to FERC account numbers requires a large number of

conversion tables. PG&E frequently changes the underlying subaccounts, making new tables necessary and rendering other tables of limited use.

"c. PG&E was unable to retrieve data needed in a timely fashion.

"d. PG&E's accounting manual procedures are outdated. (Exh. 104, pp. 1-3 to 1-5.)" (DRA opening brief, p. 4.)

PG&E has announced plans to develop a new financial management information system (FAMIS), which will include the general ledger system and related systems:

> "Expected benefits to be derived from FAMIS include intangibles such as improved flexibility to allow rapid response to changing market needs, enhanced ability to capture and monitor project costs accurately and to close out jobs on a more timely basis, and increased ability for PG&E to provide competitively priced energy supplies. Tangible benefits will include significant cost savings when the Financial Information System is fully implemented in 1993, which will help offset other company cost increases at that time.
>
> "At the time of this filing, the FAMIS project is still in the conceptual stage. The design and implementation stages will begin later this year and will continue through 1990. Initial rough estimates of 1990 costs and benefits for FAMIS (in 1987 dollars) include expenses of $7.3 million compared to cost avoidance of $4.5 million. Although these estimates are preliminary, they have been used in developing the 1990 Test Year A&G estimates." (Exh. 6, pp. 10A-4, 5.)

DRA believes that PG&E has an obligation to keep the Commission fully informed as to the development of that system. DRA asks that PG&E be directed to involve DRA and other Commission staff at sufficiently early stages to ensure that Commission input is taken into account in the development of the new system. DRA also believes that the new system should meet the requirements of the FERC Uniform System of Accounts, as prescribed by the Commission.

In response to the DRA audit recommendations, PG&E submitted the testimony of Gloria Gee, PG&E's Controller. Gee testified that PG&E is willing to provide periodic written information to the DRA concerning the status of the new accounting system. However, Gee stresses that the "primary users" are PG&E's employees, and that PG&E will accept DRA's comments on the new system "if they do make sense and if they do save time and money." (Tr. 51:5552.)

We cannot conclude that PG&E's statement is a sufficient response to the legitimate needs of the Commission for timely, accurate, and usable financial records in conformance with the uniform system of accounts. While we applaud PG&E's desire to save time and money, savings at PG&E must not be obtained at the expense of the Commission's need for timely, accurate and usable records. For example, PG&E objects to the use of FERC accounting numbers in PG&E's data fields. PG&E asserts that this additional information could cost PG&E $1 to $5 million annually. Thus, PG&E believes that DRA should be content to use the translation tables. DRA has not testified how much additional cost it incurs to use these tables, but however much time it takes, it is too much. The translation tables are bulky, complex, awkward and extremely time consuming. The effect of these tables is to frustrate and delay regulatory oversight. Our auditors' time is a scarce resource and each hour devoted to translation is an hour not available for more important tasks. The clear inference of PG&E's position is that it is less costly to translate PG&E account numbers to FERC account numbers than to incorporate the information directly into the accounting system. We will accept the inference for the purposes of this decision, and direct PG&E, effective January 1, 1990, to itself directly translate all account information before submitting such information to the Commission in any form. Such translation shall be done promptly, and shall be excused only with the express consent of the Commission staff.

So that the accounting system which is developed fully meets both the needs of PG&E management and our needs of effective and timely regulatory oversight, we will establish specific procedures for ensuring PG&E's cooperation:

1. PG&E shall file written reports with the Executive Director, beginning February 1, 1990, and at least each 90 days thereafter, on the development of the accounting system. The report shall focus in particular on work which is to be initiated in the coming quarter, and upon changes in the system which will influence the Commission's ability to audit and review the accounts and records of the company.

2. PG&E personnel responsible for the development of the new system shall meet and confer with DRA and CACD on these quarterly reports, if requested to do so by the Executive Director.

3. The Executive Director may submit written questions, comments or suggestions to PG&E on the system, within 45 days of receipt of each report.

4. If PG&E elects not to adopt the suggestions of the Executive Director, in whole or in part, it shall explain why it does not do so in the first quarterly report following receipt of the Executive Director's comments.

5. All reports by PG&E and written comments by the Executive Director, shall be filed in this proceeding.

6. The development of PG&E's new accounting system will be considered, as necessary, in this proceeding.

PG&E is requesting an increase of $2,800,000 in A&G expenses to fund the development of FAMIS. The estimate of costs and savings is preliminary, the timetable for development is uncertain and the design is unknown. We approve this expense item with considerable reservation, and only on the condition that the money is used to develop a system which fully satisfies both the needs of PG&E management and our needs for effective regulatory oversight.

c. <u>1987 Labor Adjustment</u>

DRA proposes an adjustment to the recorded 1987 labor expense of $11,962,000 (1987 $) for the electric department and $6,520,000 (1987 $) for the gas department. DRA explains the adjustment as follows:

> "PG&E has used the year 1987 as a base year in this general rate case. In most cases, for estimating operating expenses, PG&E starts with a 1987 recorded amount and adds adjustments on top of that number to arrive at a 1990 estimate. In many cases, DRA has employed the same methodology in making its expense estimates.... DRA's concern with the use of 1987 data is in regard to the labor expense. During 1987, PG&E experienced a significant reduction in labor due to voluntary retirements and other workforce reductions which were part of a major cost savings effect on the part of the company. The use of recorded 1987 labor expense as a base for estimating 1990 expenses, will result in the estimate not fully reflecting the savings that were realized in 1987. This is because the labor reductions were not achieved entirely at the beginning of the year, but over the course of the whole year. 1987 recorded labor therefore reflects salaries of people who eventually left the company. A more proper 1987 labor base to use in estimating 1990 expenses would be one which reflected the labor reduction for the whole year. Therefore, DRA normalized the 1987 recorded labor used in its estimates to reflect end of year staffing for the entire year." (Exh. 102, p. 16B-1.)

PG&E believes that DRA's proposed adjustment should be rejected because (1) it is inconsistent with PG&E's estimating methodology for test year expenses, (2) it makes unjustified assumptions about changes in PG&E's workforce, and (3) it imposes an arbitrary, extra productivity adjustment on PG&E.

Before we turn to PG&E's objections to the proposed adjustment, it is useful to consider the history which led to this recommendation.

On December 18, 1986, four days before we issued D.86-12-095, PG&E announced plans to decrease its workforce by up to 2,500 employees (up to 8.3% of PG&E's total workforce) by the end of 1987, the test year on which D.86-12-095 was based. TURN and the Commission's Public Staff Division (PSD, now named DRA) filed petitions for modification of D.86-12-095. TURN and PSD both asked that the Commission require PG&E to file detailed analysis of the cutback plan, in order to allow the Commission to determine what adjustment, if any, should be made in the rates authorized by D.86-12-095. Both PSD and TURN believed that the announced workforce reductions would result in a substantial reduction in the revenue requirement in the test period.

In response, PG&E denied that the announced workforce reductions would result in a significant decrease in the revenue requirement in the test year:

> "Stated simply, the benefits which will flow from the workforce reduction plan will primarily be realized in the years following 1987 but the costs will be incurred now. This result reflects the fact that the substantial start-up and one-time costs which will be incurred in 1987 for the workforce reduction program will be absorbed in 1987, while the efficiency and productivity benefits which result will appear in later years...PG&E intends in subsequent years to reduce or forego rate adjustments, including attrition adjustments, and to otherwise reduce rates to the extent such actions are possible as a result of these workforce reductions." (PG&E Response, pp. 5-6, January 13, 1987, A.85-12-050.)

PG&E's response emphasized that the workforce reduction would occur gradually over the entire test year 1987 and that most of the benefits would not be fully realized until 1988 and 1989.

In D.87-04-074 we stated that it was important to determine the impact of the cutbacks:

> "Our goal is not necessarily to adjust test year 1987 utility rates, but to evaluate the impact of the cutback on the 1987 base in relationship to cost benefit impacts in subsequent years. Accordingly, we will order PG&E to file an advisory cost-benefit update on these issues...." (D.87-04-074, p. 5.)

As we indicated in D.87-04-074, we are keenly interested in determining the impact of the labor reduction on the 1987 base, so that our estimate of expenses in future years fully reflects the effect of the cutbacks. While PG&E asserts, in its opening brief, that the 1987 recorded expenses already incorporate significant benefits from cost control measures put into effect during 1987, this assertion does not refute the fact that the recorded figures do not fully reflect the full benefit of the reductions achieved by the end of 1987.

PG&E states that its estimates of 1990 expenses, both the base estimate and any adjustments to the base, were made by deciding whether 1987 as a whole represented a "normative" level of expense and activity. (PG&E Brief, p. 72.) Although PG&E has explained how it prepared the estimates, PG&E has not explained why, in light of the major workforce reduction, it did not rely instead on the end of year 1987 data. Assume, for example, that a department began the year with 100 employees; through a planned workforce reduction program of layoffs and attrition the department ends the year with 90 employees. To assume, based on the recorded year average, that 95 employees would be needed the next year is not a reasonable deduction. We agree with DRA that end of year 1987 data must be explicitly factored into the estimate of test year expenses.

PG&E's second objection is that DRA did not consider the effect of workforce reductions on nonlabor expences, "even though there may very well be an increased use of outside services." PG&E offers no authority for the proposition that the workforce reduction might cause an increase in outside services. Nor does PG&E attempt to quantify the effect of this alleged increase on DRA's adjustment, although it had ample opportunity to do so on the record. Moreover, PG&E's inability to provide a timely accounting of the expenses incurred for outside services in the test year (see Section III.C.5.c.) has denied DRA the opportunity to contrast and compare labor expenses with outside service expenses.

In the same vein, PG&E believes that DRA's analysis could have used headcount and labor costs in different combinations which could have resulted in a lower adjustment. PG&E cites transcript page 1379. Here DRA witness Fukutome explains that he initially attempted an adjustment based on headcount alone, but PG&E's project manager indicated that he thought dollar amounts would be a more accurate way of reflecting this adjustment.

Finally, PG&E believes that the proposed adjustment imposes an extra productivity adjustment on PG&E. PG&E is incorrect. As DRA states, the multifactor productivity model is not used to establish a revenue requirement. Instead, all that may be said of the multifactor productivity model is that the account-by-account estimate of productivity gains is "contained within a reasonable confidence interval of the productivity model estimate." (PG&E opening brief, p. 20.) Thus, as DRA witness Yazdani testified,

> "The two approaches can be used in a complimentary way to validate the results of each other, but it is definitely wrong to calculate a productivity figure using one approach and claim that the second approach already incorporates that productivity gain." (Exh. 106, p. 10.)

We conclude that the results of the productivity model did not foreclose an otherwise reasonable adjustment to the PG&E accounts reflecting labor expenses in the test year. Moreover, even if we assume arguendo that DRA's adjustment were to impose an additional productivity adjustment, we would find such an adjustment to be entirely reasonable. In D.86-12-095 we reduced PG&E's operating budgets by 2%, or about $31 million. As we explained:

> "Given that PG&E's operating expenses are over $1.5 billion annually, this modest adjustment establishes a reasonable goal that PG&E should be able to achieve by instituting new productivity and cost-cutting programs. We believe that such additional cost-cutting is imperative if PG&E is going to respond to the increasing level of competition it faces in both the gas and electric industries." (D.86-12-095, mimeo. p. 37a.)

Therefore, even if DRA's 1987 labor adjustment could be characterized as a further productivity adjustment, this adjustment is approximately half of the productivity adjustment we adopted in the last general rate case. We will adopt DRA's labor adjustment to normalize 1987 labor expenses.

d. <u>Gain on Sale</u>

DRA proposes an adjustment of $3,644,000 for gains on sale of property. DRA believes that gains from the sale of nondepreciable property should be passed on to ratepayers.

> "In the base year 1987, there were gains from the sale of utility property totalling $2,186,434 that were booked in Account 421.1, Gain on Disposition of Property, a below-the-line account. The gains, therefore, were passed on to the stockholders. The property sold was included in PG&E's rate base from the time of its purchase, which ranged from 1902 to 1971, until its sale. Since this was the case, the gains should have been recorded above the line in Account 411.6, Gain on Sale of Utility Property."

PG&E did not offer testimony in rebuttal to DRA's proposed adjustment. PG&E's witness Forsgard indicated that PG&E disagreed with DRA's recommendation, but she did not explain why. However, PG&E strongly objects to the proposed adjustment in its opening and reply briefs.

PG&E's first objection is that the transfer of these costs to Account 411.6, rather than 421.1, would "overrule the FERC Uniform System of Accounts on this issue." PG&E's argument misconstrues the function of the Uniform System of Accounts. The USOA is a bookkeeping system, not a ratemaking policy. When we established this system of accounts we stated explicitly "that the Commission does not commit itself to approve or accept any item set out in any account for the purpose of fixing rates or determining other matters which may come before it." (D.42068, 48 CPUC 253, 257.)

Regardless of where a gain on the sale of property may be recorded, our practice in Edison's recent general rate proceeding, for property originating in Accounts 101 and 103 and transferred to Account 121 prior to sale, was to allocate the gains between shareholders and ratepayers based upon the time the property was in rate base. (D.87-12-066, mimeo. p. 10.)

Second, PG&E seeks to excuse its failure to offer testimony rebutting DRA's proposal by reference to A.87-07-041, regarding the gain on sale of Southern California Gas Company's headquarters building:

> "In that proceeding, PG&E has presented the company's position in the testimony of Thomas C. Long. PG&E urges the Commission to consider the policies established in that more-detailed proceeding when evaluating the merits of the Staff proposal. Meanwhile, PG&E asks the Commission to recognize that the company is in full compliance with the current FERC/CPUC rules regarding transfers to Accounts 411.6 and 421.1." (PG&E Opening Brief, p. 70.)

A.87-07-041 is not a generic investigation. It is a proceeding focusing on a specific financial transaction involving one utility. That utility is not PG&E. PG&E is of course welcome to offer evidence and argument on the question of Southern California Gas' sale of its headquarters. However, PG&E's participation in that proceeding as an interested party will not resolve the question of the gain on sale of PG&E's property. Indeed, were we to decide A.87-07-041 in a manner adverse to PG&E's position and concurrently apply that result to decide matters pending in this general rate case, we would expect PG&E to object that such action was beyond the scope of A.87-07-041.

PG&E's opening brief asked us to consider the policies established in A.87-07-041 when evaluating the merits of the DRA proposal in this case. PG&E's reply brief asks us to revise the policy on gain or loss on sale in the context of the more detailed record in A.87-07-041, rather than on the record in this case where the only evidence is the testimony of DRA's auditor. PG&E seems to be making two different requests.

On the one hand, PG&E seems to request that we defer a decision on the gain on sale of its property until we decide A.87-07-041. Of course, when our decision in A.87-07-041 is issued, that decision may serve as a precedent to guide our resolution of other similar factual disputes. But we have no assurance either that a decision in A.87-07-041 will issue prior to the decision in this case, or even if it did, whether such decision will be applicable, much less controlling, to the matters at issue here. Therefore, PG&E's request to defer the gain on sale issue in this proceeding is denied.

On the other hand, PG&E seems to ask that we base our decision upon the record in A.87-07-041. In effect, PG&E is asking that we consolidate the record of A.87-07-041 and A.88-12-005 on this issue, so that we might consider the testimony which PG&E offered in A.87-07-041. Rule 55 permits proceedings involving related questions of law or fact to be consolidated. Had PG&E made a motion to consolidate in a timely and proper manner, we would have given the motion due consideration. But if a party seeks to consolidate two proceedings it must provide us and all other parties notice of its intent to request such action at the earliest possible opportunity, certainly before the close of the respective records in each case. A reply brief is simply too late for a party to make such a motion.

Absent a timely and proper motion to consolidate the record of another proceeding, we must decide the issues before us in this proceeding in the context of the record before us. We have in evidence the testimony of DRA's auditors in support of a change in Commission policy. We have the applicant voluntarily electing not to offer rebuttal evidence. That is the basis on which we will decide this issue.

Third, PG&E disagrees with the position of DRA that the gains booked to Accounts 102 and 253 in 1987 should have been immediately transferred to Account 411.4:

> "These properties were transferred to PG&E Properties (then JWP Land Company), a wholly-owned subsidiary of PG&E. Financial Accounting Standard 71 clearly states that "an enterprise does not recognize profits on sales to unregulated affiliates because the profits are not validated by transactions with outside parties." (FASB Statement of Standards, p. 1882, FAS71, paragraph 85.) In other words, PG&E should not recognize any gain or loss from transfer of property from PG&E to PG&E Properties until the property is sold to an outside party. DRA's position violates accounting standards and should be rejected." (PG&E Opening Brief, p. 71.)

In response, DRA notes that PG&E has quoted the FASB 71 out of context. FASB has not determined that utilities should not recognize profits on sales to unregulated affiliates. Instead, FASB 71 merely reports that most respondents to a previously issued discussion memorandum indicated that they do not recognize profits on sales to unregulated affiliates.[21]

Again, DRA has made a proposal for accounting treatment and offered testimony in support of that proposal. PG&E has not offered evidence to rebut the proposal. PG&E alleges in its brief that the proposal violates accounting standards, but the sole authority offered to support this contention is not in the record and is quoted out of context.

Finally, in its reply brief, PG&E also argues that there is no evidence in this proceeding to determine whether the properties sold in 1985-87, upon which DRA based its reduction, were ever in rate base. This argument is too little and too late. DRA's testimony states "the property sold was included in PG&E's rate base from the time of its purchase, which ranged from 1902 to 1971, until its sale." This testimony was received in evidence. PG&E had every opportunity to cross-examine DRA on the basis of this statement. PG&E did not do so. PG&E had every opportunity to offer rebuttal evidence to show that any of these properties had not been in rate base, again it did not do so. PG&E could even have argued about the validity of DRA's evidence in its opening brief, but did not do so. Having failed to avail itself of various opportunities to rebut or refute DRA's evidence, PG&E's argument carries no weight with us when raised for the first time in its reply brief.

Because PG&E failed to make a timely and appropriate showing in this proceeding regarding its proposed treatment of this item, we will adopt DRA's proposal and allocate the gain to the ratepayers. Since PG&E has not included an estimate of

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21 FASB 71 is not in evidence. Where DRA cites from FASB, PG&E has argued that we must ignore references to a document not in evidence.

Account 411.6 in its test year operating revenues, it was appropriate for DRA to derive an estimate. We will adopt DRA's estimate of $3,644,000. The decision in this case is not intended to establish a precedent for our decision in A.87-07-041 on treatment of the gain from the sale of the SoCal Gas headquarters building. That case will be decided based on the record in that proceeding.

D. Gas Department Expenses

Table 2 presents a comparison of PG&E's and DRA's estimate of gas department results of operation for the test year, as well as the revenue and expense estimates which we adopt in this decision.

1. Production Expenses

Gas production expenses are all expenses, excluding fuel, associated with the operation and maintenance of PG&E's gas production facilities. To forecast base expenses in the test year, PG&E relied upon 1987 recorded expenses. DRA agrees with PG&E's base estimates. DRA and PG&E differ in only two respects. One difference involves the transfer of hazardous waste expenses. (See Section III.E, infra.) The other difference concerns Account 742, Maintenance of Production Equipment.

For Account 742, DRA recommends $1,011,000 for the internal corrosion project, $239,000 less than PG&E. The purpose of the program is to provide information regarding the integrity of the gas collection system and to identify additional corrosion mitigation measures. DRA's detailed review of the program identified significant schedule delays. PG&E maintains that these schedule delays resulted from the late start of the project in 1988 and do not represent a future trend. However, PG&E acknowledges that the number of pumps, probes, and dehydrators to be installed cannot be determined until further evaluation is made. PG&E's witness, Lipscomb, did not have personal knowledge of the status of

TABLE - 2

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
SUMMARY OF EARNINGS AT PRESENT RATE
REVENUES AND EXPENSES
(Thousands Of 1990 Dollars Unless Otherwise Indicated)

Description	PG&E	DRA	ADOPTED
Operating Revenues	$1,040,929	$1,040,929	$1,040,929
Operating Expenses			
Production	14,846	11,994	12,130
Transmission	32,139	31,868	31,989
Distribution	112,602	109,435	109,575
Customer Accounts	73,327	72,261	73,327
Uncollectibles	1,943	1,943	1,943
Customer Service & Informational	34,860	32,199	35,589
Administrative & General	170,364	142,130	155,528
Franchise Requirements	7,304	7,304	7,302
Other Adjustments	0	(19,490)	(6,520)
Subtotal (1987 Dollars)	$447,385	$389,644	$420,863
Labor Escalation Amount	25,850	21,619	24,285
Non-Labor Escalation Amount	21,024	19,415	20,020
Subtotal (1990 Dollars)	$494,259	$430,678	$465,168
Natural Gas Used by the Gas Department	(141)	(141)	(141)
Project Amortization	6,837	6,837	6,802
Depreciation	188,857	183,831	187,996
Taxes Other Than On Income	43,766	40,546	42,581
Superfund tax	473	473	360
CA Corporation Franchise Tax	24,451	31,867	28,132
Federal Income Tax	86,687	110,366	98,854
Total Operating Expenses	$845,189	$804,457	$829,752
Net Operating Income	$195,740	$236,472	$211,176
Rate Base	$2,167,780	$2,092,246	$2,137,560

the testing program. If PG&E had such information, it did not provide it to this record.

DRA's disallowance is also based on the difference in cost in corrosion inhibitors. PG&E's estimate is based on the cost of an inhibitor it expects to be available in 1990. DRA recommends a lower cost based on the fact that the new inhibitor is not yet available and PG&E has not determined which inhibitor or inhibitors will be used in the test year.

We agree with DRA that PG&E has not adequately supported its request for for full funding of the internal corrosion project. We will adopt DRA's adjustment of $239,000.[22]

2. Storage Expense

Except for a hazardous waste adjustment (see Section III.E, infra), PG&E and DRA agree on the base estimate of storage expenses in the test year.

In Account 831, structures and improvements, PG&E requests $2,000,000 per year for the McDonald Island Levee Repair. The actual costs of the repair are not known at this time. PG&E believes that the annual cost may range from $677,000 in the best case to $2,709,000 in the worst case, with $2,000,000 to be the most likely case. DRA agrees with PG&E's estimate. FEA recommends $1,693,000, which is an average of the best and worst cases. This would be an appropriate methodology if we assign equal probability to the best and worst cases. However, both DRA and PG&E believe that the outcomes are not equally likely. Recognizing that the actual costs may fall anywhere within these two estimates, we believe that PG&E's estimate, to which DRA concurs, is reasonable.

22 FEA proposed an alternative method for calculating a disallowance for Account 742. We agree with PG&E that FEA's calculation is in error and we do not adopt it.

3. Transmission Expense

PG&E and DRA differ in two areas.

First, in Account 851, PG&E requests $655,000 for additional gas control manpower. DRA recommends $429,000. While DRA agrees that additional positions may be needed, DRA believes that the need for additional positions is not as great as indicated by PG&E. In response, PG&E asserts that DRA has not taken into account the specific regulatory requirements in effect in 1990. However, PG&E has not identified these specific regulatory requirements, nor quantified the increased effect of these requirements in the test year. In the absence of more specific justification by PG&E, we will authorize an increase of $550,000 for additional gas control manpower.

In Account 857, PG&E requests $71,000 for expenses associated with measuring and regulating additional gas meter stations. DRA recommends $43,000. In Account 865, PG&E requests $18,000 for maintenance of these additional stations. As we explain above, we adopt DRA's estimate of gas meter stations to be installed. We adopt DRA's estimate for Accounts 857 and 865.

4. Distribution Expense

PG&E and DRA differ in their estimates of gas distribution expenses in three areas: (1) Hazardous waste (see Section III.E), (2) Pipeline replacement program (PRP) and (3) Overall services, fleet maintenance.

Both DRA and PG&E calculate the M&O component of total 1990 PRP expenditures using a ratio. DRA used the ratio of recorded 1987 M&O expenses to the recorded total 1987 expenditures. PG&E used the ratio of M&O expenses from 1987 job estimates to the recorded total 1987 expenditures. PG&E's "job estimate" ratio assumes a higher percentage of M&O expenses for cast iron and steel pipeline replacement than was actually recorded in 1987, resulting in a higher estimate of increased M&O expenses.

According to PG&E, PG&E has requested additional O&M expenses of $4,571,000 for PRP work; the DRA recommends $1,987,000 leaving $2,584,000 at issue. PG&E states that the $2,584,000 is needed to maintain the current schedule of the Pipeline Replacement Program.

> "The reason for PG&E's increase in M&O Expense is a shift in work for the program, with additional emphasis on replacing deteriorated distribution main in San Francisco. (PG&E, Exhibit 7, pp. 8-12, 8-13.)
>
> "This increase corresponds with the overall shift in the program. The City of San Francisco contains a large percentage of cast-iron distribution piping scheduled for replacement. The population density in San Francisco is the highest in the PG&E system; homes and businesses are often built with little or no open space between them. Meter relocations in San Francisco often require a substantial effort to meet current codes and standards." (PG&E, Exhibit 7, pp. 8-13; Lipscomb, Tr. 165.)

PG&E argues that DRA has ignored all of the analysis associated with the shift in the PRP, particularly the shift of work to San Francisco. PG&E notes that its estimate of capital expenditures was reduced to account for this shift in the program.

DRA denies PG&E's charge that it ignored the shift in work to San Francisco. While San Francisco work will increase, DRA points to a net decrease in the PG&E systemwide miles of main and service replacement from 1987 to 1990.

Although PG&E insists that DRA's estimate expense level will not be adequate to fund the pipeline replacement program PG&E plans in 1990, PG&E has not clearly articulated why its estimate of these expenses based on a "job estimate" ratio is a more accurate predictor than a ratio based on recorded expenses. In particular, PG&E has failed to explain how its estimate accounts for both the increase in San Francisco work and the systemwide decrease in miles of main and service replacements. PG&E has not met its burden of demonstrating the need for its requested increase in M&O expenses. We will adopt an increase in the PRP program, but only up to the level recommended by DRA.

DRA also proposes removal of $72,000 for "cosmetic repairs" to vehicles. DRA believes that this work is of no benefit to ratepayers. PG&E argues that this work is part of normal maintenance, and refers to its workpapers which are not in evidence. While we would have preferred PG&E to offer evidence on this question, we see obvious benefit to maintaining the vehicles in good repair. As long as cosmetic repairs are distinguished from the corporate identity program, the expense is reasonable.

5. Customer Accounts

We adopt PG&E's uncontested estimate of $73,327,000 for Gas Customer Account expense.

6. Administrative and General

All issues in the gas department Administrative and General accounts which are common to the electric and gas departments have been discussed earlier in this decision, under the electric department. The only issue unique to the gas department involves account 930.2, Miscellaneous General Expenses.

DRA and PG&E disagree concerning the portion of American Gas Association (AGA) dues to be excluded.

PG&E adjusted the 1988 AGA dues of $718,908 to remove 40.5% or $291,158 for advertising expenses. The balance was reduced by 0.6% or $2,567 for lobbying expenses.

In D.85-12-108, an SDG&E general rate case, we allowed 99% of the nonadvertising portion of AGA dues. In D.86-12-095, PG&E's last general rate case, we followed the SDG&E decision and allowed 99% of the nonadvertising portion of AGA dues. PG&E urges us to follow these previous decisions and disallow 0.6% of AGA dues as associated with lobbying.

DRA proposes to exclude $52,000 more than PG&E. DRA examined the "Audit Report on the Expenditures of the American Gas Association (for the 12 month period ending December 31, 1987)" by NARUC, and determined a 43.4% disallowance for advertising and a 9.5% disallowance for lobbying expenses, representing a further disallowance of $52,000 for AGA dues.

In rebuttal, PG&E states that the NARUC audit of AGA does not provide the same level of detail or the same categories as the EEI audit. Until the AGA audit is performed at the same level of detail as the EEI, PG&E believes that the Commission should maintain the disallowance of lobbying expenses at the level of 0.6%.

As with the NARUC audit of EEI, all parties refer to the AGA audit but no party offered it into evidence. Therefore, to ensure a complete record we will move the audit report into evidence, on the Commission's own motion. The "Audit Report on the Expenditures of the American Gas Association (for the 12 month period ending December 31, 1987)" is received into evidence as Exhibit 401.

Our examination of this report reveals that substantially more than 0.6% of the expenditures of AGA are related to lobbying. We also have concerns with the charitable and political contributions made by AGA. Our examination of the AGA audit satisfies us that DRA's disallowance reasonably approximates the portion of the AGA dues attributable to lobbying, contributions, and advertising. We will adopt DRA's disallowance.

7. <u>Gas Plant</u>

PG&E's estimate of test year weighted average gas plant is $25,377,000 higher than DRA's estimate.

Gas Meter Stations

PG&E proposes to install additional major gas metering stations to more efficiently track gas on the PG&E system. PG&E's goal is to capture 80% of the gas in its distribution system. PG&E estimates that this may require up to 50 additional meters.

In its original application, PG&E proposed to install 12 meters per year between 1989 and 1992. However, in February 1989 PG&E revised the schedule as follows:

1989 - 0
1990 - 20
1991 - 15
1992 - 15

PG&E estimates $7,505,000 ($3,858,000 test year weighted) to place 20 meters in operation in 1990. DRA recommends $4,695,000 ($2,485,000 test year weighted) for installing 12 meters in 1990. DRA notes that PG&E allocated funds to design only 12 meters in 1989. DRA believes that PG&E's plan to install 20 meters in 1990 may be overly ambitious. PG&E, on the other hand, believes its revised plan to install 20 meters in 1990 is sound and urges us to adopt the schedule recommended by the experts closest to the project.

Despite the proximity of PG&E's experts to the project, they have not satisfactorily reconciled PG&E's decision to defer installations in 1989 with its decision to accelerate the schedule in 1990. We agree with DRA that the schedule originally proposed by PG&E to install 12 meters in the first year of the program is a reasonable basis for funding this project in the test year. We also agree with DRA that it would be poor planning and unfair to the ratepayers to authorize funding for more meters than may be needed or for more meters than can be installed in the test year. We will adopt DRA's estimate.

Residential Automated Meter Reading

PG&E requests $7,297,000 ($3,617,000 test year weighted average) for residential automated meter reading. DRA opposes funds in the test year for this project.

PG&E is investigating five types of metering technologies. PG&E plans to test two of these technologies in 1989. These are the two technologies which PG&E's project manager believes to be most promising. If one of these two meters proves acceptable, PG&E plans to install 5,000 of these meters, beginning in 1990. The 5,000 meters will be installed in a pattern that would replace the work of a meter reader to allow PG&E to evaluate the operational feasibility and cost-effectiveness of the meters. If neither of the first two meters proves successful, PG&E will test the other three meters in 1990 and defer the capital expenditures for this program until 1991.

DRA recommends that PG&E complete technological feasibility tests of all five meter types before installing 5,000 meters for operational tests. PG&E has not explained why it is reasonable to proceed with the operational phase of this program before it completes its technological assessment of the five meter types. In the absence of such explanation, we adopt DRA's recommendation to exclude funds for this project from capital expenditures until the first phase of the RD&D program has been completed for all five meter types.

Milpitas Terminal and Pipeline Relocation

PG&E has included $22,257,000 ($6,492,000 test year weighted average) for modernization of the Milpitas Gas Terminal and $3,266,000 ($139,000 test year weighted average) to relocate pipelines in the vicinity of the Milpitas Terminal. Both projects were authorized in the 1987 test year, but delayed to the 1990 test year due to California Transportation's (Caltrans) failure to adopt a design for the highway adjacent to the terminal.

DRA recommends no funding for these projects until the 1993 test year. Since PG&E has already accrued a rate of return and depreciation expense on facilities that were not actually constructed, DRA reasons that exclusion of the capital funds between 1990 and 1992 will offset the funds previously accrued. In response, PG&E notes that test year ratemaking necessarily requires an estimate of new plant will be added. Sometimes projects reasonably forecasted to occur will be delayed. Similarly, PG&E must also necessarily incur capital costs for projects which were not forecasted. We agree with PG&E that both of these situations are a normal condition of ratemaking based on estimates of test year expenses. Absent evidence of fraud or negligence on the part of the applicant (and none is alleged here), it would be unfair to single out projects which were delayed in the test year without crediting PG&E for projects which may have been added or accelerated in the test year.

DRA also opposes funding the Milpitas projects because of uncertainty regarding potential reimbursement to PG&E from Caltrans. Since Caltrans and has accepted responsibility for delay of the projects, Caltrans has agreed to reimburse PG&E in the form of a contribution in aid of construction. Caltrans has not yet estimated the amount of reimbursement. PG&E estimates a reimbursement of $1,500,000 in 1990 and has deducted this amount from the costs of the Milpitas projects. We agree with PG&E that uncertainty over the magnitude of the reimbursement should not preclude PG&E from any recovery for a beneficial project which is reasonably forecasted to occur in the test year. Accordingly, we will adopt PG&E's estimates for the two Milpitas projects.

Meter Protection Program

The purpose of the meter protection program is to bring all gas meters up to current safety codes. PG&E requests $4,958,000 ($2,497,000 test year weighted average). DRA opposes the request.

DRA states, without citation to the record or other authority, that it understands that the capital funds for the Meter Protection Program are in the Gas Pipeline Replacement Program. We are at a loss to understand how DRA arrived at this understanding. We understand that the Meter Protection Program will focus on areas not covered by the Gas Pipeline Replacement Program, using priorities agreed upon by PG&E and the Commission's Safety Division.

DRA also opposes funding of the program because DRA has not been provided adequate justification for this request. In response, PG&E indicates that this is a new program, initiated in conjunction with the Commission's Safety Division. PG&E asks the Commission to recognize the difficulty in developing detailed estimates for a new program with no historical data.

While PG&E has provided few details regarding implementation of the program, the absence of supporting detail is understandable in this instance. The program is new and specific priorities and details will be worked out in conjunction with the Commission's Safety Division. We will approve $4,958,000 for the first year of this program. We will not adopt DRA's request that PG&E be ordered to modify or relocate a specific number of meters each year, but we will adopt DRA's suggestion that PG&E file an annual report on the Meter Protection Program with the Commission's Safety Division. This report shall be in the same format and filed at the same time as the annual report on the pipeline replacement program which PG&E submits pursuant to D.86-12-095. The first annual report on the meter replacement program shall be filed May 1, 1991. This report will allow the Commission to monitor the progress and costs of these related programs.

<u>Rio Vista Projects</u>

Three projects (Rio Vista Corrosion Inhibitor Pumps, Rio Vista Collection System Piping, and Gas Well Dehydrators) are part of a program which PG&E initiated in 1988 to reduce the level of internal corrosion in its gas collection system. In Section III.C.1 of this decision we adopt DRA's estimate for M&O expenses of the internal corrosion project. Because the M&O costs of the program are linked to the plant costs, we also adopt DRA's estimates of the plant costs. We recognize that PG&E takes this project very seriously and that the project manager offers assurance that the schedule will be met. Despite PG&E's best intentions, PG&E's inability to adhere to the hydro testing schedule in 1988 does not augur well for 1990. We will therefore adopt DRA's recommendation to estimate the costs of this project slightly below the level of maximum improvement requested by PG&E.

1988 Plant In-Service

In PG&E's rate application, filed in December 1988, PG&E provided recorded 1987 plant-in-service and an estimate of 1988 additions. As in past general rate cases, PG&E provided recorded 1988 plant-in-service, as soon as the data was available. Five projects which were recorded in 1988 were not included in the estimate of 1988 expenses included in PG&E's application. DRA alleges that these projects were operative in 1987 but not placed into the accounting records until 1988.[23] DRA alleges that PG&E was not diligent in keeping its books up to date and that these projects should not be allowed in the test year rate base estimate.

In response, PG&E states that the estimates contained in the NOI and Application are forecasts which do not "perfectly capture the operational data of every capital project in a company of PG&E's size. PG&E further argues that the rate case plan does not permit major changes between the filing of the Notice and the Application. PG&E believes that DRA's argument that these five

23 DRA's assertion that the projects were operative in 1987 is not supported by citation to the record. However, PG&E did not dispute this contention.

projects should have been identified earlier than March 1989 "would seem to require PG&E's forecasters to have crystal balls or second sight." (PG&E Reply Brief, p. 86.)

While PG&E takes exception to DRA's assertion that PG&E should be more diligent in preparing its estimate of 1988 plant additions, PG&E does not address the specific projects DRA proposes to exclude. The standard rule is that the capital cost of new plant should be recorded when it becomes operational. If a plant is placed in service in 1987, especially if it is a major plant addition, PG&E is expected to include that plant in its estimate of 1988 additions. In this instance, PG&E does not explain why five projects which were operational in 1987 could not be included in an estimate of 1988 plant prepared in the spring of 1988. Nor does PG&E explain why these additions could not be included in the update to the NOI, which was filed with the application in December 1988. In this update, PG&E revised gas rate base to reflect additional rate base and other plant. PG&E does not explain why these five projects could not have been operational at that time.

In past cases we have used recorded plant-in-service data two years prior to the test year as the basis for estimating test year expenses. The use of this recorded data may differ from the estimate of plant additions contained in the application. This is acceptable, so long as the applicant has been reasonably diligent in providing an accurate estimate of plant additions. In this instance, PG&E failed to include in its estimate over $9,000,000 in projects placed in-service 12 months or more before the application was filed.

We find that PG&E had more than sufficient time to include plant placed in-service in 1987 in its 1988 estimate of plant additions. Under these circumstances, we will not include these projects in the test year estimate. We will adopt DRA's recommendation for 1988 plant in service of $221,099,000.

Abandoned Plant

PG&E requests authorization to amortize miscellaneous abandoned projects under $100,000 each. The total direct cost is $140,000.

PG&E asserts in Exhibit 7: "These additional projects meet the Commission's criteria for recovery." The miscellaneous projects are not listed or otherwise identified in PG&E's testimony. PG&E does not explain how these projects meet the Commission's criteria.

As we discuss in Section III.C.6.a. of this decision, PG&E has requested amortization of the direct costs of certain electric plants which do not meet the Commission's criteria. Therefore, we are reluctant to authorize the amortization of any gas plant, however small, in the absence of an affirmative showing which clearly demonstrates that these projects actually meet our stated criteria. PG&E's request to amortize $140,000 in abandoned gas plant is denied.

8. Other Issues

All issues relating to administrative and general expenses, taxes, depreciation, working cash, and DRA's additional proposed adjustments are common to both the electric and gas departments. These issues have been discussed in Section III.C. of this decision.

E. Hazardous Waste

In PG&E's last general rate case, we carefully reviewed PG&E's manufactured gas plant program. The purpose of the program is to identify former gas plant sites, to investigate the sites for potentially hazardous materials and to clean up or mitigate the hazardous materials, to the extent they may exist.

In that case PG&E proposed a budget of $26,697,000 to investigate six sites per year and to cleanup four sites per year. PG&E estimated the costs of site investigation to range from

$40,000 to $400,000, with 90% of the site investigations to average $335,000.

DRA recommended funding in rate base only for investigations. DRA recommended that the costs of cleanup be placed in a special deferred account for later recovery. DRA estimated investigations to cost between $25,000 to $250,000. DRA recommended an average of $100,000 per site, for seven site investigations per year.

As we stated in D.86-12-095, "we are convinced that hazardous waste management is an increasingly important public health matter." In D.86-12-095, we determined that the appropriate ratemaking treatment for manufactured gas plant cleanup is to place the cost of site investigations in rate base, while allowing recovery of site cleanup costs through a special ratemaking procedure.

We authorized $2,000,000 per year for investigations and program development, including ongoing investigations of manufactured gas plant sites at a rate of at least ten sites per year. The rate of investigations which we set for PG&E, at least ten sites per year, was higher than PG&E estimated, but necessary, in our view, given the increasing importance of this vital public health matter. The amount we authorized per site investigation was lower than PG&E's average estimate but entirely adequate, in our view, "to fully support a financially sound and viable cleanup effort." (D.86-12-095 mimeo. p. 65c.)

PG&E's progress in conducting site investigations over the past three years has been very disappointing. According to PG&E's testimony, it has only eight sites under active investigation, will initiate investigations at three sites in 1989 and anticipates investigations at three new sites per year thereafter.

Although we authorized $2,000,000 per year for site investigations, PG&E spent an average of only $1,250,000 on site investigations in 1987 and 1988. Instead, PG&E charged a portion of the mitigation costs at one site to the program, even though we had not authorized use of the $2,000,000 for that purpose.

PG&E offers several explanations for its failure to adhere to the schedule we set in D.86-12-095. First, PG&E argues that it did not proceed at the rate of ten sites per year because it believed the decision contained conflicting goals. The "conflicting goals" were the requirement of at least ten sites per year and the allocation of $2,000,000 per year. According to PG&E's witness, PG&E did not consider the funding to be adequate, "That, to me, was the conflicting goal." (Tr. 14:1409.)

This is not an acceptable excuse. If PG&E believes that funding to meet a specific goal is inadequate, PG&E's proper recourse is to petition for modification and offer additional evidence in support of its proposed funding level. PG&E did not do so here. Instead, PG&E simply ignored the goal. Moreover, even if PG&E believed the funding to be too low to investigate ten sites per year, it was clearly sufficient to fund more sites than PG&E actually investigated. PG&E did not spend all of the money we authorized for investigation in either 1987 or 1988.

PG&E's second explanation for failing to investigate at least ten sites per year, is that neither PG&E nor federal and state agencies had the staff resources to manage a program of that magnitude. Of course, if PG&E believed this to be true, there were appropriate steps that could be taken to adjust the goal, once PG&E had informed us of a legitimate resource need or limitation.

PG&E's third explanation is made in its opening brief. PG&E states that lacking significant near term public health risk, it is not prudent to accelerate the current pace of the manufactured gas plant program. PG&E offers no citation to the record for the proposition that there is no near-term public health risk at the sites which have not yet been investigated. The very purpose of the investigations is to determine the extent of the risk. Moreover, even if there were no near-term risk, PG&E must be equally concerned about the cumulative, long-term public health effects from potentially contaminated sites.

Having failed to meet the goals we established for site investigations and failed to spend the funds we previously authorized, PG&E now requests that we authorize an additional $2,477,000 per year to fund investigation of the same sites in the coming three years. As DRA correctly notes, ratepayers have already funded the investigation of 30 sites in the last rate case cycle. PG&E has not yet used all of the money previously provided for this purpose.

In response to DRA, PG&E asserts that it is clear that the Commission's cost estimates were low and that PG&E should not bear the burden of this underestimate. We are not persuaded that our previous estimate is low. The estimate is for an average of 30 sites. While the higher priority sites are expected to cost more, the lower priority, smaller, less complex sites will cost less. On balance, our estimate of $200,000 per site investigation appears reasonable, as long as PG&E does not charge the costs of remediation or other noninvestigation expenses to this program.

PG&E's request for additional funding for site investigations is denied without prejudice. We expect PG&E to complete its investigation of the sites it now owns, approximately 31, with the resources we previously provided, and we expect PG&E to do so before it files its next general rate application. PG&E shall be excused from undertaking or completing an investigation at a particular site only if it can document that the delay is caused by factors outside of its control, or if the responsible oversight agency concurs in the decision not to further investigate a particular site.

If PG&E has fully and prudently expended for site investigations the $6,000,000 we previously authorized and has not completed its investigation of all of the sites it owns, PG&E may apply by advice letter for additional funds to investigate any remaining sites.

In D.86-12-095 we required PG&E to file an annual report of its hazardous waste program and related expenditures, and we provided that the reporting requirement will terminate in 1989 unless expressly extended in the next general rate case. At DRA's request, we will extend this requirement for another three years.

Underground Tanks

PG&E requests $682,000 for cleanups at leaking underground storage tanks. We authorized underground tank cleanup costs in base rates in the 1987 general rate case. PG&E's request is based on statistics of the costs of 37 tank cleanups in 1987, and on a tank forecast failure model.

DRA believes that underground tank cleanup costs are difficult to estimate in size, number, and costs. DRA believes that the cost of underground tank cleanups should be recovered through the same memorandum account procedure which we have adopted for other remediation costs. Yet, in D.88-09-020, where we recently reviewed the various categories within PG&E's hazardous waste program, DRA agreed with PG&E that base rate recovery should continue for those categories of expenses, including underground tank cleanup, as authorized in D.86-12-095. We then held:

> "We agree and will expect PG&E to request recovery of those items through base rates in its next GRC." (D.88-09-020, mimeo. p. 40.)

Having found in both D.86-12-095 and D.88-09-020 that it is appropriate for PG&E to recover underground tank cleanup expenses in base rates, we see no need to revisit the issue again in this proceeding. We adopt PG&E's estimate of $682,000 for the test year.

Surface Impoundments

PG&E estimates $5,415,000 in capital costs for the surface impoundment program in 1990. DRA estimates $3,035,000 because DRA anticipates that PG&E will obtain a variance from the Regional Water Quality Control Board that will allow the company to save $2,380,000 in the test year.

Both DRA and PG&E believe that the variance is likely to be granted. Who then should be at risk for the possibility that the variance will not be obtained? DRA believes that shareholders should underwrite the risk that the variance will not be granted. PG&E believes that DRA's proposal could unfairly penalize PG&E for trying a more cost effective approach. We agree with PG&E. We will authorize $5,415,000. If the variance is obtained, PG&E shall consult with DRA to identify other appropriate environmental-related uses for the amounts saved from issuance of the variance.

Environmental Compliance Projects

As described above, in D.86-12-095 we established a new mechanism for recovery of certain hazardous waste costs. Pursuant to this procedure, PG&E filed A.87-10-019 requesting approval to accrue the costs of 22 projects in a memorandum account. In D.88-03-017 we authorized interim memorandum account treatment for the projects listed in A.87-10-019. Thereafter, in D.88-09-020 we authorized PG&E to book into a memorandum account expenses incurred after March 9, 1988, the effective date of interim D.88-03-017, in relation to particular projects. We also concluded that PG&E should not book into the memorandum account any expenses incurred prior to March 9, 1988.

PG&E applied for rehearing of that portion of D.88-09-020 which limited recovery to those costs incurred after March 9, 1988. By D.88-12-049, we modified D.88-09-020, to provide that while PG&E chose to expend funds for capital projects outside of the established procedure and cannot recover these costs through the memorandum account, PG&E is not absolutely precluded from recovering all such capital costs, to the extent they are found reasonable during PG&E's next general rate case.

DRA objects to the recovery of these costs by PG&E at this time. DRA contends that the request, submitted May 2, 1989, was provided too late in the proceeding to permit DRA and other parties to review the request. DRA suggests, in its opening brief, that there is another proceeding, A.89-05-001, which is specifically dealing with the reasonableness of these projects. DRA believes that these costs should be reviewed in A.89-05-001, if at all.

Thereafter, on October 5, 1989, at the prehearing conference in A.89-05-001, PG&E moved that the pre-March 9 costs for these two environmental compliance projects be considered in that proceeding. PG&E's motion was granted by ALJ Garde.

On October 25, 1989, DRA filed in this proceeding a petition to set aside submission and reopen the general rate case on the issue of an adjustment to FERC Account 925 related to these particular environmental compliance projects. According to DRA's petition, PG&E has recently completed the installation of measures to mitigate fallout-type particulate (FTP) air pollution. DRA requests an opportunity in the general rate case to propose a reduction in Account 925 to reflect the benefit of lower claims payments that will result from the completion of PG&E's FTP mitigation projects.

PG&E response to DRA's petition, dated December 7, 1989, opposes DRA's petition. First, PG&E believes that DRA had every reasonable opportunity to pursue this issue during the hearing process. PG&E asks that DRA's petition be denied, or in the alternative, that the issue of Account 925 be reopened to permit both PG&E and DRA to submit updated information, on a comparable basis, on all expenses included in Account 925.

We will grant DRA's petition to set aside submission relating to FTP claims, injuries and damages in account 925. Given the fact that PG&E did not request rate relief for these projects until May 2, 1989, very late in the general rate case proceeding, we find that other parties did not have a reasonable opportunity to pursue this specific issue in the hearing process.

We will also grant PG&E's alternative requests that all of Account 925 be reopened to permit PG&E to submit updated information on all expenses included in Account 925. Earlier in this decision we approve PG&E's full request for Account 925, with amortization of the Carmen settlement payments. Recognizing that to fully reopen consideration of Account 925, as PG&E requests, will require more time than DRA's limited motion to set aside submission on a specific issue, we will provide that all Account 925 expenses incurred by PG&E in 1990 shall be subject to refund, pending our further review of this account.

F. Productivity

In A.88-12-005, PG&E provided testimony which estimated the productivity for the gas and electric departments in test year 1990. Based upon its study of multi-factor productivity (MFP), PG&E reported an historical annual productivity growth rate of 3.6% for the electric department and 1.5% for the gas department for 1976 through 1987. For test year 1990, PG&E projected productivity growth rates of 4.8% and 3.2% for the electric and gas departments respectively.

DRA reviewed PG&E's testimony and conducted an independent study of PG&E's productivity. DRA verified that PG&E's model fairly represented the historical period. DRA was particularly pleased with the projected productivity for 1990. These projected levels are above PG&E's average productivity gains for the past twelve years. "It was encouraging to see from the model's results that the Company appeared to be striving to be even more efficient than it historically has been." (Exhibit 10, p. 4.)

After the application was filed, PG&E and DRA discovered that each had a different view of how to apply the results of the

MFP study. It was DRA's opinion that the test year revenue requirement should be reduced to reflect the productivity savings which the model predicted would be realized in 1990. Apparently, according to DRA, PG&E's multifactor productivity witness "understood that if the company manages to be more productive, and realizes costs savings due to higher productivity, it can keep these savings and pass them on to its shareholders."

In response to a DRA data request regarding the relation of the ambitious estimated productivity growth rates to the cost estimates presented by PG&E's other witnesses, the company re-estimated the model by adding new variables and changing forecasted inputs. PG&E's revised estimate, presented February 7, 1989, forecasts 3.5% productivity gain for the electric department and 0.9% for the gas department for 1990. The combined overall productivity, according to the revised forecast, is 2.7%. Therefore, according to PGE's revised forecast, approximately $135 million in fuel and non-fuel productivity savings are reflected directly or indirectly in PG&E's estimate of 1990 test year expenditures.[24]

While DRA is concerned that PG&E's revised forecast appears to be outcome oriented and while DRA believes that PG&E's projected productivity falls below historical levels, DRA states that the revised approach by PG&E for forecasting productivity appears to be reasonable.

In PG&E's last general rate case we made a productivity adjustment in addition to the productivity savings which were embedded in PG&E's 1987 revenue requirement. We reduced operating expenses of the electric and gas departments by 2%, or about $31

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24 When PG&E revised the forecast of test year productivity it also lowered the estimates of average historical productivity to 1.7%.

million. A similar 2% adjustment in this proceeding would amount to approximately a $33 million reduction. As no party has requested such an adjustment in this case, we will not give it further consideration, except to note that by not making the adjustment we provide PG&E's management $33 million more flexibility in test year 1990 than in 1987.

We are very satisfied with PG&E's effort to prepare a multifactor productivity analysis for this proceeding and with DRA's careful review of that analysis. We will ask PG&E to present another multifactor productivity analysis in its next general rate case, and as part of the analysis, that PG&E demonstrate how the forecasted multi-factor productivity gains are reflected in its test year revenue requirement request.

G. Women and Minority Business Enterprises (W/MBE)

Both PG&E and the Commission's W/MBE Program coordinator presented testimony regarding PG&E's efforts to ensure that women and minority owned business enterprises are provided equal opportunity to contract for products and services purchased by PG&E. PG&E's testimony described the organization, operation and achievements of the W/MBE program.

As reported by PG&E and confirmed by the W/MBE Coordinator, in 1987 1,313 W/MBE firms received $102,700,000 of business with PG&E, representing 8.8% of total corporate expenditures. In 1988, W/MBE firm received $152,600,000 of work, or 12.2% of corporate expenditures. PG&E has significantly exceeded its short term goals of 6% participation by minority owned enterprises and 5% participation by women owned enterprises. We commend PG&E for attaining the goals set pursuant to General Order (GO) 156.

While the W/MBE Coordinator recognizes PG&E's accomplishments to date, he also believes that PG&E's W/MBE program can be further improved. He has offered several suggestions for improving PG&E's W/MBE program. In particular, he suggests that

PG&E should specifically target and improve the participation of business enterprises owned by minority women.

In D.89-08-041, we recently clarified the question of goals relating to businesses owned by minority women. Specifically, we amended § 6.3 of GO 156 to require that goals be established for both minority women owned business enterprises and non-minority women owned business enterprises. These goals are to be a subset of the overall goal for W/MBEs established by § 6.2 (initially 20% for both women owned business enterprises and minority owned business enterprises). These goals are intended to ensure that utilities do not direct their W/MBE procurement programs toward non-minority women and minority men owned business enterprises to the detriment or exclusion of minority women owned business enterprises.

We also addressed the recording of contracts with minority women owned business enterprises toward compliance with the goals set forth in GO 156 § 6.2. This section provides for initial long-term goals of not less than 15% for minority owned business enterprises and not less than 5% for women owned business enterprises, but does not specify a goal for minority women owned business enterprises. For the purposes § 6.2, contracts with minority women-owned business enterprises can be counted toward either the minority owned business goal or the women owned business goal, but not toward both.

While we recognize the success to date of PG&E's W/MBE program, we agree that even a successful program can be improved. We urge PG&E to give serious consideration to each of the recommendations presented in the W/MBE Coordinator's testimony for improvement of its program. The W/MBE Coordinator may renew these recommendations, if necessary, in the next annual review of PG&E's W/MBE program.

D.88-04-057, as modified by D.88-09-024, requires the utilities to jointly establish a central clearinghouse for the sharing of information on the identification and verification of W/MBE firms. PG&E estimates its cost in establishing and maintaining the central clearinghouse to be approximately $756,000 for the 1990 calendar year. PG&E anticipates that this level of spending will continue through 1992. We find the cost to be reasonable and will increase Account 923 by this amount.

Decision 89-08-026 also established a new annual proceeding for review of utility W/MBE programs. In its update exhibit, PG&E requests an additional $142,000 to cover the cost of one analyst/coordinator, one clerical support person, and one-quarter time of an attorney, for participation in the new annual proceeding. PG&E believes that its request is reasonable, moderate, and truly reflects the additional costs it will incur in the test year.

In D.89-08-026 we stated:

> "One party favoring the rate case option believed that an annual generic proceeding could result in significant expansion and cost increases between rate cases. It is not clear whether this cost increase would be due to program expansion or additional staffing for a generic proceeding. We do not agree that either is likely. WMBE programs are not new, just reviewed by this Commission under new legislation. Thus, initial staffing and costs for implementing programs have been established." (D.89-08-026, mimeo. p. 13.)

In this case, we do not know whether the increased costs requested by PG&E are for the preparation of the annual W/MBE report, a cost which is already funded, or for merely for PG&E's participation in the annual proceeding. If the increased costs are merely for participation in the proceeding, 2.25 person years seems extraordinarily high. For these reasons, PG&E's request is denied.

H. <u>PG&E Enterprises</u>

PG&E Enterprises (Enterprises) was formed as a wholly owned-subsidiary of PG&E in January 1988. Enterprises, in turn, wholly owns four subsidiaries, Angus Petroleum Company, NGC Energy Company, JWP Land Company, and an unnamed operations and maintenance company. Enterprises is also a partner in a joint venture with Bechtel.

Between December 1988, when PG&E filed its general rate case application and May 1989, DRA conducted a review of the general structure and financial relationship between Enterprises and PG&E. DRA presented the results of this review in a "Report on PG&E Enterprises." (Exhibit 152.) DRA considers the results of its review as being both preliminary and limited. The Report describes the general organization of Enterprises and its subsidiaries, general accounting practices for intercompany transactions, valuation of PG&E services to Enterprises, financing of Enterprise activities, and other topics.

Based on this limited review, DRA recommends an adjustment to PG&E's test year revenue requirement of $552,800, to reflect DRA's estimate of costs relating to the value of information which will be chargeable to Enterprises in 1990. DRA also presents recommendations regarding (1) access to Enterprise's books and records, (2) reporting requirements of Enterprise/PG&E transactions, (3) the transfer pricing of information and intellectual property, and (4) provision of various financial documents. In addition, DRA recommends that the Commission adopt comprehensive guidelines governing intercompany transactions. DRA asks that the Commission order PG&E and DRA to jointly develop these guidelines using the guidelines in D.88-01-063 (Edison holding company case) as a basis.

In response to DRA's recommendations, PG&E offered rebuttal testimony on PG&E Enterprises. The testimony was sponsored by Joseph O'Flanagan. The testimony describes the purposes of PG&E in establishing PG&E Enterprises, and responds to some of DRA's specific recommendations.

PG&E's rebuttal testimony did not specifically address DRA's recommendation that the Commission adopt comprehensive guidelines governing intercompany transactions, but in its reply brief, PG&E proposes eight guidelines for Commission adoption.

TURN contends that the Commission must ensure that PG&E Enterprises receives no ratepayer funded benefits of any kind. Recognizing PG&E's plans to increase Enterprises' capitalization by two billion dollars over the next five years, TURN urges the Commission to act now to establish strong ratepayer protection against cross-subsidization and other forms of self dealing.

TURN advances seven major points:

1) A standard of "ratepayer indifference," at which PG&E is permitted to transfer goods or services to Enterprises at less than the market price, does not adequately protect ratepayers,

2) Labor services should be provided at market rates,

3) Ratepayers should actually be reimbursed for Enterprise's use of PG&E employees. According to TURN, no mechanism exists for reflecting the reimbursement from Enterprises in rates during the period covered by the rate case:

> "In other words, to the extent Enterprises uses existing utility employees whose full salaries are included in rates, PG&E will be paid twice for the same employees - once by ratepayers and once by Enterprises. Enterprises' reimbursement will not affect rates until the 1990 actual expenses which include Enterprises' payments are used to set rates for test year 1993. (Tr. V. 62, pp. 6719-20: O'Flanagan/PG&E.) In the meantime, the reimbursement from Enterprises will only increase shareholder profits." (TURN Opening Brief, p. 19.)

TURN recommends an interim reduction in labor expense of $880,000, representing the annualized level of Enterprises' use of PG&E employees in 1988, plus 10% markup for profit.

4) Management time should be fairly allocated to Enterprises. During 1988 PG&E's top management allocated

approximately $5,000 per month to Enterprises. TURN believes that this amount is insufficient.

5) PG&E failed to forecast Enterprises' use of PG&E equipment during the test year. TURN recommends a $6,000 credit to account for use of such equipment as corporate automobiles and aircraft.

6) Ratepayers should not subsidize Enterprises via PG&E's R&D Department. TURN recommends that PG&E's budget be reduced by $1,930,000 to reflect the cost of research designed to benefit Enterprises.

7) TURN recommends an audit to comprehensively evaluate the relationship between PG&E and Enterprises. As TURN explains in its opening brief:

> "TURN believes that effective protections against cross-subsidies and other forms of self-dealing can only be derived through a comprehensive review of transactions between PG&E and Enterprises and the establishment of specific guidelines to allocate <u>all</u> shared costs between them. (Exhibit 298, pp. 6-7.)
>
> "TURN believes that this review and the recommendation of appropriate guidelines is best accomplished through a management audit where independent auditors analyze the pricing of transactions between PG&E and Enterprises, the allocation of management cost, the allocation of shared facilities' costs, and review methods of isolating PG&E's cost of capital from any effects due to Enterprises. The management audit should recommend appropriate guidelines and ratemaking treatment in these areas." (TURN Opening Brief, p. 24.)

<u>Discussion</u>

The formation of PG&E Enterprises by PG&E does not involve a change in the ownership or control of the utility. Therefore, unlike SDG&E's and Edison's recent reorganization proposals, PG&E's plan to establish non-utility subsidiaries does not require our authorization pursuant to Public Utilities (PU)

Code § 854. Although PG&E does not require our authorization to form PG&E Enterprises, this aspect of PG&E's operations is of concern to us. Regardless of the particular corporate structure, there is a need for proper oversight of intercorporate and intracorporate transactions. "There is always the risk that when affiliates and utilities do business together, holding company organization or not, that improper allocations will result in higher costs of service and, therefore, higher rates than necessary." (D.88-01-063, mimeo. p. 22.)

Where utilities and affiliates propose to do business, we have placed stringent conditions in order to minimize the risks to ratepayers. These conditions fall into five general categories:

1. Commission access to information,
2. Accounting and recordkeeping practices,
3. Financial effects of nonutility operations,
4. Human resource effects of such operations, and
5. Transactions between utility and nonutility affiliates.

As we stated in D.81896, and reaffirmed in D.86-01-026,

> "A special burden must be borne by the applicant in a rate case to demonstrate conclusively not only that affiliated intercompany transactions are reasonable in that they do not create a burden on the consumer, but that the affiliated relationships afford the maximum gains in efficiency or productivity and the greatest savings in costs to the consumer." (D.86-01-026, p. 33.)

In this general rate proceeding PG&E has not met its burden of demonstrating conclusively that its affiliate intercompany transactions have been or will be reasonable.

Despite the importance of accurately allocating costs between a regulated utility and unregulated subsidiaries, PG&E did not make an affirmative showing in this proceeding on the effect of Enterprises on results of operation in the test year. PG&E simply asserted, in rebuttal testimony, that no expenses related to PG&E's services to Enterprises were included in the revenue requirement forecast.

Despite the fact that Enterprises was formed early in 1988, that Enterprises had ambitious plans to grow in 1989, 1990, and beyond, and that PG&E planned to provide personnel and other resources to Enterprises in this endeavor, PG&E's application did not address the conditions under which these transactions would take place. Even when DRA proposed specific guidelines in May 1989, and PG&E indicated its willingness to accept "reasonable guidelines," PG&E did not expressly state its view of what those guidelines should be, until it filed its reply brief.[25] These guidelines are a useful starting point for our development of more comprehensive standards. But, the guidelines have been introduced far too late in the proceeding to permit a meaningful review.

Several parties cite our D.88-01-063, in which we authorized Edison to form a holding company. While this decision provides some useful guidance, it is not dispositive of the matters before us. First, that decision was carefully developed in response to the particular proposal presented by Edison. Without a better understanding of the nature and structure of the transactions between PG&E and Enterprises, it is not apparent that

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25 PG&E's rebuttal testimony, portions of which were sticken, and PG&E's supplemental brief, which incorporated these stricken portions as argument, explain why PG&E is opposed to various DRA guidelines, but do not provide a clear picture of what guidelines PG&E would support. For example, rather than explain the accounting controls which will be employed to protect against cross-subsidization, PG&E simply states that it agrees to assist the Commission in fulfilling its obligation to ensure that Enterprises is not being subsidized by ratepayers. We welcome PG&E's offer of assistance. We wish, however, that PG&E's offer had been manifested in this proceeding by a clear and complete description of the controls which are now in place at PG&E to fulfill that purpose.

the terms of D.88-01-063 are applicable. Second, many of the terms of D.88-01-63 were adopted after DRA had an opportunity to examine Edison's proposal. "In that regard, one strong factor that convinced us to approve the reorganization is the position of DRA, which has worked diligently towards compromise and accords with Edison that had their genesis in the SDG&E decision." (D.88-01-063, mimeo. p. 23) In this proceeding, DRA informs us that its review to date has been preliminary and limited. Under pressure to file testimony in this proceeding before the close of hearings, DRA did not have time to conduct a complete audit of the relationship between PG&E and Enterprises. Last, but not least, we find no reason to lock ourselves into a singular approach to a constantly evolving situation. As we noted in D.86-01-026,

> "The endeavor of reviewing holding company expenses and their allocation is always evolving, and it must be borne in mind that the Telesis corporate family poses a particular ratemaking challenge because it is relatively new and highly diversified, and seems intent on becoming more so. The regulator has no choice but to view costs assigned to utility subsidiaries by holding companies very skeptically, especially where the corporate family is in diversified lines of business, because there is always the motive and temptation to have as many costs as possible borne by the utility's monopoly operations." (D.86-01-026, p. 53.)

We note the testimony of PG&E witness O'Flanagan. While this testimony explains PG&E's objections to DRA's proposals, the testimony sheds little light on the scope or nature of transactions between PG&E and Enterprises. O'Flanagan is Director of the Revenue and Earnings Section in the Revenue Requirements Department. Up until the time he was assigned to respond to DRA's recommendations on Enterprises, O'Flanagan had no involvement with Enterprises. As a result, he had no direct knowledge of the interactions between PG&E and Enterprises. In the brief time he had to prepare his testimony, he was not able to fully familiarize himself with basic information about the operation of Enterprises. He did not know how PG&E and Enterprises compensation policies and pension plans compared. He was not aware of the circumstances under which jointly funded research is made available to Enterprises before it is published. Because O'Flanagan was not directly involved with Enterprises and because of his limited review of its operations, his testimony failed to fully explain the nature and scope of intercompany transaction, much less demonstrate conclusively why they are reasonable.

One important theme of O'Flanagan's testimony is that the operation of Enterprises will not conflict with the operation of the utility. O'Flanagan testified that the primary purpose of PG&E's utility employees is to provide utility service, and the provision of services to Enterprises is secondary or incidental to the primary utility service. In contrast, PG&E's MIP (discussed earlier in Section III.C.5.b.) does not characterize services by PG&E employees to Enterprises as secondary or incidental. To the contrary, providing equally responsive service to all business units, including Enterprises, is an explicit goal and measure of individual performance for many corporate center units. The MIP also lists the performance of specific tasks related to Enterprises as part of the overall performance goals, and such tasks are to be performed within the limits of authorized budgets. The goals as reflected in the MIP, appear to place equal emphasis on three areas: Utility operations, Diablo Canyon, and Enterprises.

Given PG&E's failure to offer a timely affirmative showing on affiliate transactions in this proceeding, PG&E's belated proposal of guidelines pertaining to such transactions, and DRA's limited and preliminary review of such transactions, we conclude that there is insufficient evidence on this record for us to determine the proper allocation of costs between PG&E and Enterprises in 1990; nor is there a sufficient record for us to adopt, at this time, guidelines relating to transactions between PG&E and Enterprises.

The record will remain open for the receipt of additional evidence on this issue in a subsequent phase of this proceeding. As a first step in the next phase, PG&E is directed to undergo a management audit, to be conducted by an independent management consulting firm.

The study should be a coordinated operational and financial audit of its processes as well as its management performance. The focus of the audit should be on management procedures used to allocate utility resources, including human and financial resources, between PG&E and its subsidiary PG&E Enterprises. The study should investigate, among other matters, (1) the transfer of goods and services between PG&E and Enterprises, including physical assets such as land, (2) billing, financial and recordkeeping practices, (3) cost allocation, and (4) personnel practices. The review should study and report on PG&E's internal processes as well as the measurable results of the processes (for example productivity measures.) The audit should include specific recommendations for improvements in PG&E's management methods.

In order that the management audit be thorough and impartial, the study should be performed by an experienced management consulting firm. The consultant should be selected with attention to avoiding conflict of interest problems relating to the firm's other business with PG&E (or its subsidiaries or affiliates), or within the gas and electric industries.

The Commission Advisory and Compliance Division (CACD) should appoint a Project Coordinator to coordinate the audit project and consultant contract administration.

The Project Coordinator should assemble a Commission review group to actively participate in all aspects of the audit administration: issuance of a request for proposal, contractor selection, audit progress reports and final report draft review. In order that the Commission may direct and control the audit effort, the Project Coordinator should approve the request for proposals/bid package, bidder list, contractor selection criteria, final contractor selection and contract document.

The Project Coordinator should determine an audit work plan, including project milestones and reporting requirements. A draft final report should be submitted for Commission review two months prior to submission of the final report. The Project Coordinator may impose additional reporting requirements as necessary, including progress reports. The consultant must be available for possible testimony in the proceeding.

The consultant contract shall be between the management consulting firm and PG&E. However, consultant efforts should be directed by the Project Coordinator, and consultant invoices should be approved for payment by the Project Coordinator. The contract should cover the audit study and reports.

It is important that PG&E participate in this audit in a spirit of cooperation. PG&E should afford the consultant personnel the same access to company documents and personnel that the Commission staff would have if it were conducting the audit itself.

The proceeding will remain open to consider the audit report and recommendations. Following review of the report and other relevant evidence, we may order an adjustment in attrition year revenues related to affiliate transactions. It is the intention that PG&E be allowed to recover in rates its net audit payment costs. Recovery of recorded audit costs may be offset by reduced company expenses induced by implementation of audit recommendations.

As a final note, DRA moved to strike portions of PG&E's brief relating to Enterprises. Since we are not taking final action on this issue at this time and because the record will remain open, DRA is not prejudiced by the inclusion of this material as argument in PG&E's supplemental brief. The motion is denied.

I. Attrition

PG&E makes its request for increases in the attrition year revenue requirements based upon the Attrition Rate Adjustment mechanism adopted in D.85-12-076. The purpose of this procedure is to limit and simplify attrition adjustments. PG&E and DRA agree on many parts of the mechanism. However, PG&E and DRA differ in three areas:

- Gas pipeline replacement program
- Capital related productivity
- Non-recurring O&M.

Gas Pipeline Replacement Program

DRA proposed that the calculation of plant additions in the attrition years be based upon a seven-year average of additions (in constant dollars) for projects under $50 million. PG&E agrees with the use of a seven year average for all projects under $50 million, except for the gas pipeline replacement program. PG&E believes that a seven-year average will understate the capital additions for this program in 1991 and 1992, because the average incorporates years in which the project costs were less than current or projected levels. Therefore, PG&E proposes that the costs of the gas pipeline replacement program be separately forecasted and specifically stated.

We agree with DRA that mixing forecasted costs with estimated costs could lead to distorted results. If the averaging approach is reasonable, and we believe it is, the average may understate the costs of some projects and overstate the costs of other projects. Overall, we expect that the differences will balance out and lead to a fair result.

Therefore, we will use a seven-year average for all plant additions under $50 million.

Capital Related Productivity

In testimony that is tentative and uncertain, DRA questions whether productivity is properly accounted for in the methodology for calculating capital related attrition. DRA suggests that

> "DRA's last concern with PG&E's methodology for calculating capital related attrition is that productivity seems to be neglected. It is true that productivity reflected in historic plant addition data is reflected in attrition year estimates, but since those numbers are averaged amounts, the reflected productivity is also only averaged. Also there would be no accounting for productivity gains beyond the recorded years. For items which are budgeted, it is uncertain whether productivity gains realized between the time of the budget and the time of construction have been incorporated in the project estimate. It appears there are no productivity gains beyond 1988 reflected in 1991 and 1992 plant estimates. DRA realizes that this lack of reflecting future productivity on the capital side is true for all energy utilities, but DRA believes that it should no longer be totally ignored in the attrition analysis." (Exhibit 10.)

In order to "at least reflect some gains in productivity," DRA proposes to reduce the rate of escalation by one-half for electric and gas distribution expenses for 1991 and 1992. DRA also recommends that in future general rate proceedings, PG&E should make a showing on the effect of productivity on capital expenditures.

We agree with DRA that the methodology used to calculate capital expenditures in attrition years should properly take into account the effect of anticipated productivity. However, we agree with PG&E that DRA has not presented an adequate factual or analytical foundation to support its proposed productivity adjustment. At a minimum, it is first necessary to determine the extent to which productivity is presently captured in the historic plant addition data and in the estimates of budgeted expenditures. In particular, DRA's proposal to reduce the rate of escalation by one-half, in the absence of any quantitative analysis, appears to be entirely arbitrary.

PG&E's testimony identifies a number of programs that are intended to increase its productivity in carrying out capital projects, such as computer-based estimating, combination crews, and computerized gas estimating. We are anxious to learn from PG&E how the productivity which results from these programs is fully reflected in the attrition year estimates. We will direct PG&E to make a detailed showing, in its next general rate application, on the effect of productivity on distribution capital expenditures in test and attrition years. Both PG&E and DRA shall propose a method for ensuring that the productivity in capital distribution projects is fully reflected in attrition years.

Nonrecurring O&M

DRA states that $17,224,000 in electric department expenses and $300,000 in gas department expenses which are requested by PG&E for the test year are nonrecurring costs and should be excluded from the calculation of the revenue requirement in the attrition years. Alternatively, DRA proposes in its reply brief that nonrecurring expenses be amortized over the three year rate case period. DRA's position is that if an adjustment is made to a normalized test year amount derived from recorded information, the adjustment should be examined to determine whether the expense will also be incurred in the attrition years. If it appears that the expense will continue, or that expenses will be incurred for similar activity, then the adjustment should carry into the attrition years. However, if it appears that the adjustment represents a one-time, abnormal or non-recurring expense, PG&E should not be permitted to collect for a one-time expense in three successive years.

In its rebuttal testimony, PG&E urges the Commission to reject DRA's adjustment for nonrecurring O&M. PG&E believes that the attrition mechanism adopted by the Commission in D.85-12-076 does not permit a detailed examination of expenses or activities that may cause attrition year expenses to increase or decrease after the test year. In addition, PG&E argues that it would be unfair to remove non-recurring test year expenses from attrition years, without allowing PG&E an opportunity to demonstrate that other new one-time expenses will occur to offset DRA's proposed reductions. PG&E also argues that DRA's description of these expenses does not adequately demonstrate that the expenses are actually nonrecurring. "On the contrary," PG&E states, "a number of the programs are ongoing in nature." (PG&E Opening Brief, p. 272.)

We have addressed this issue before. In SDG&E's 1986 test year general rate case, DRA similarly argued that one-time expenses incurred in the test year, while legitimate in that year, will not be incurred in subsequent attrition years. DRA argued that to allow 100% of the expense in the test year without a subsequent attrition adjustment would allow recovery for the same expense three times before the next general rate case. DRA also argued that it is too difficult to track these items to ensure that they were excluded in the attrition year filings. Therefore, DRA proposed that the one-time expense be amortized over three years.

SDG&E argued, on the other hand, that while these expenses are one-time for the test year, there are other similar expenses that will occur in the attrition years which are not considered because of the current ratemaking methodology which only looks to the test year. Thus, SDG&E's position was that in any one year, test year or attrition year, there will always be "one-time" expenses.

Upon careful review of SDG&E's arguments, which are very similar to those advanced in this case by PG&E, we were

> "...persuaded by the staff that the most proper treatment is to recognize the expense if reasonable but to spread the expense over the

> three-year rate case cycle. We realize that this might not allow full recovery of a legitimate expense but we also realize that these projects are in the control of the company and that any delay beyond the estimated completion dates is a windfall for the utility. In these circumstances, it appears reasonable to follow the staff's suggestions. It is also readily apparent that the cause of this issue is the current ratemaking plan of conducting a general rate once every three years." (D.85-12-108, mimeo. p. 5.)

Similarly, in this case, we are convinced that it is proper to amortize nonrecurring expenses which are incurred in the test year over the three-year rate case cycle. While the proposal is true that PG&E may incur unforeseen expenses in attrition years, overcollection for nonrecurring test year expenses is not an appropriate source of revenue to fund these increases. Instead, as we explained in D.85-12-076, we expect additional productivity and management acumen will offset activity growth, customer growth, and new mandated programs during the attrition years. As we have stated before, the attrition mechanism may not encourage wastefulness but neither does it encourage frugality. To allow full recovery of one-time test year expenses in each of the following attrition years would encourage wastefulness. We will therefore amortize these costs over three years.

Finally, we turn to PG&E's argument that DRA has not adequately demonstrated that particular expenses are nonrecurring. We do not agree. DRA has identified the account, the item, and the amount. DRA has offered a witness to testify that these expenses will not occur. PG&E was free to examine the witness or to rebut the testimony as to the specifics of any item. PG&E did not do so. PG&E's rebuttal asserted that a number of the programs are ongoing in nature, PG&E has not identified these programs, although it would have been quite easy to do so. In the absence of evidence to the contrary, we must accept DRA's estimate of non-recurring O&M expenses in the test year.

IV. Research, Development, and Demonstration

PG&E states that it developed its research, development, and demonstration (RD&D) program to fit with its long-term resource plan and to pursue four general strategies: 1) to reduce costs and enhance the use of existing assets; 2) to reduce the risks and effects of energy supply; 3) to retain customers by improving productivity and services; and 4) to put the company in a position to take advantage of future technologies.

DRA generally supports PG&E's proposals. DRA proposed several adjustments to PG&E's initial budget that PG&E accepted. DRA recommended a decrease in the funds for small cogeneration research, a reduction of dues for industry associations, the addition of a residential automated meter reading project, and a contribution to the California Institute for Energy Efficiency (CIEE). PG&E accepted all of these changes, and presented a modified budget in Exhibit 13-B.

Exhibit 13-B incorporates nearly all the recommendations of DRA, but it does not reflect the remaining difference between DRA and PG&E (Tr. 25:2493). DRA also recommends reducing the allowed dues paid to the Electric Power Research Institute (EPRI) to the extent that those dues relate to the Diablo Canyon nuclear power plant. This reduction amounts to $2,900,000. DRA also stated its reservations about the effect of the affiliation between PG&E and PG&E Enterprises on RD&D.

TURN also raises concerns about the complications that the affiliation between PG&E and PG&E Enterprises creates for determining the proper level of RD&D funding. TURN recommends reducing the RD&D budget by a total of $1,930,000 to reflect the cost of research designed to benefit Enterprises.

ERA argues that PG&E's RD&D program neglects solar and wind generating technologies. ERA believes PG&E's cost-effectiveness analyses undervalue these technologies by understating the cost of oil and not considering the environmental effects of other generating technologies. ERA thinks the Commission should require PG&E to increase its efforts in developing these technologies.

ERA recommends that the budget for photovoltaic generation should be maintained at $1,050,000 for the next three years and that PG&E should start planning to build a 100 MW photovoltaic facility. ERA also urges PG&E to devote more of its photovoltaic efforts to residential applications.

We will adopt the basic RD&D budget presented in Exhibit 13-B. We have addressed the proposed adjustment to EPRI dues in our discussion of the allocation of costs between PG&E and Diablo Canyon, and our determination there should be reflected in the RD&D budget. The concerns raised by PG&E and DRA about the effect of the relation between PG&E and Enterprises was discussed in our examination of this affiliation, and appropriate adjustments should also be made to the RD&D budget.

With these adjustments, the basic budget presented in Exhibit 13-B is reasonable, and we adopt an RD&D budget for the test year of $36,732,000, broken down into $29,690,000 for electricity and $7,042,000 for gas.

V. Long-Term Planning

The process of converting a revenue requirement into specific rates in a general rate case begins with a consideration of long-term planning. In this step of the process, the need for energy is forecasted, and after certain assumptions are made, a resource plan is formulated. The components and results of this plan are then used to evaluate the cost-effectiveness of current and proposed demand-side management (DSM) programs, to calculate the energy reliability index (ERI), to derive marginal energy costs, and to work out a logical program of research, demonstration, and development.

The functions of the resource plan in the general rate case are different from those that are the focus of the Biennial Resource Plan Update (BRPU). The determinations we make in the general rate case should therefore not be seen as establishing any sort of precedent for the BRPU.

The primary participants on long-term planning issues, PG&E and DRA, differed in several respects. PG&E's resource plan is intended to be a least-cost plan with additions tested for cost-effectiveness. The purpose of DRA's resource plan is primarily to test the cost-effectiveness of demand-side management programs, and its proposed plan is characterized as a bare-bones plan that includes only committed resources. This primary difference colors these parties' approaches to other issues in this area.

Some of the issues related to long-term planning come up more directly in the discussion of marginal energy cost, and we have deferred our consideration of these issues to the section on marginal costs.

A. Demand Forecast

PG&E developed its own load forecast for the test year with increasing reliance on the CEC's ER-7 demand forecast until the forecasts for 1995 and beyond are entirely derived from ER-7. The resulting demands were adjusted to reflect the effects of demand-side management as forecasted in PG&E's ER-7 filing.

DRA used PG&E's load forecasts but substituted its own forecast of the effects of DSM.

As we discuss in the section on DSM, we largely adopt DRA's DSM program. The adopted resource plan should reflect the load forecast developed by PG&E, reduced by the effects of the DSM program we authorize. As set forth in the DSM section of this decision, the net effect of our DSM decisions is to reduce first-year load by 51.7 MW.

PG&E's natural gas demand forecast is based on material filed in the 1988 California Gas Report. DRA has not disputed PG&E's estimates in this case, and we will adopt this forecast.

B. Electric Resource Plan Assumptions

After electric demand is forecasted, the parties develop a resource plan to meet that demand. The resource plan depends on many assumptions about the availability and price of various sources of electric energy and capacity. Because of the complexity and size of PG&E's system, the parties rely on computerized production cost simulation models in arriving at a resource plan. In this case, PG&E relied on PROMOD 27.9, and DRA used ELFIN 1.7.

In an attempt to narrow the disputes about production cost models, we have developed procedures to help the parties isolate the real differences between them (see D.87-12-066, D.88-12-040). The process used in this case illustrated how we hope to separate the various sources of differences between the parties in this area.

The process begins with PG&E submitting a resource plan based on the results of runs using its preferred model (PROMOD) and a similar resource plan based on a reference model (ELFIN). The parties then confer to define a base case resource plan, which they then run through their preferred models. This step helps delineate the differences between the various models. Next, the parties present a list of changes they recommend to the reference model in the base case, a step that helps isolate the effects of modeling conventions. Finally, the parties recommend resource assumptions that differ from the assumptions of the reference model base case.

Many of the major issues pertaining to the subject of long-term planning relate to differences in the parties' preferred resource assumptions, and we will address those issues first.

1. Out-of-State Power Purchases

Several issues concern purchases of power from entities in other states, primarily from the Pacific Northwest region.

a. Purchases of Firm Capacity

For capacity purchases, DRA includes only the capacity associated with signed firm power purchases. PG&E argues that spot capacity should also be included and points out that the CEC has determined that the planning assumptions of ER-7 should take spot capacity into account. PG&E's resource plan for 1990 therefore includes spot capacity in its 1,890 MW of Northwest power, and the CEC in ER-7 includes 500 MW of similar spot capacity (Exhibit 70, p. G-63). TURN believes that the amount of spot capacity available from the Northwest is overstated, and PG&E has not addressed the issue of the huge returns of energy that are a condition of those purchases.

Consistent with its bare-bones approach, DRA disagrees with the CEC's inclusion of capacity from pending resources. The CEC describes these pending resources by saying, "Although not certain enough today to be considered as committed resources, the probability of the successful negotiation and execution of these contracts is great enough to require their consideration when determining the need for new resources" (Exhibit 70, p. G-55). The CEC notes that most of the resources it includes in this category are signed contracts awaiting regulatory approval or contracts with contingencies or options to obtain additional resources.

DRA argues against including these resources in the resource plan because they are not committed, as required by D.86-07-004.

We agree with PG&E and the CEC that prudent resource planning should include a consideration of the spot market for capacity from the Northwest, which has proved to be a reliable and cheap resource in recent years. We will adopt the recommendation of ER-7 and include 500 MW of spot capacity in the resource plan.

We will also adopt the CEC's findings on the amount of firm capacity PG&E will be able to purchase from the Northwest under existing contracts. In ER-7, the CEC determined that firm capacity would amount to 705 MW in the test year, declining to 215 MW by 2007, for PG&E's service area (Exhibit 70, p. B.1-7). (Comparable figures for the Northern California Planning Area are 801 MW in the test year, declining to 311 MW by 2007 (Exhibit 70, p. B.1-1).)

The CEC is not clear about its recommended treatment of the capacity it describes as pending. It believes that this capacity should be protected from displacement by more expensive QFs in our bidding process for future purchases, but it is silent about the role of this pending capacity in the resource plan. The CEC elaborates on these pending contracts:

> "These pending contracts represent existing surplus capacity that has very low cost in comparison to any likely QF or utility alternative. They are available now as spot capacity and will continue to be until long-term contracts are consummated. The only reason the contracts are not fully executed is that the parties have not yet agreed on appropriate division of the benefits of the long-term contract." (Exhibit 70, p. G-64.)

Based on the perceptions of the CEC, we will include pending resources as firm capacity in the resource plan. For PG&E's service area, these pending resources total -39 MW for the test year, increasing to 500 MW by 1994 (Exhibit 70, p. B.2-5). (For the Northern California Planning Area, pending resources show the effects of the availability of California-Oregon Transmission Project (COTP) for the municipal utility participants, and the totals rise from -39 MW in the test year to 1,263 MW in 2007 (Exhibit 70, p. B.2-1).)

For the purposes pertinent to this case, PG&E's resource plan should include estimates of out-of-state power purchases consistent with these findings of the CEC.

b. California-Oregon Transmission Project

The other major difference between the parties concerns the inclusion of capacity from the COTP, which is proposed as a joint project of several municipal and investor-owned utilities. PG&E believes the capacity from this project will be available within the planning horizon, by 1992, and PG&E therefore includes the full capacity in its resource plan. DRA excludes the project because it has not yet received the required regulatory approvals, as D.86-07-004 requires before projects are considered committed. TURN argues that COTP should be excluded because it will not be operational during the period covered by this rate case. PG&E responds that the municipal participants in the project will go ahead and construct the line even if the investor-owned participants are denied their certificates of public convenience and necessity. The CEC in ER-7 includes 848 MW of the municipal utilities' portion of the project.

We endorse the CEC's assumption that the municipal utilities will have 848 MW available to them, but we understand ER-7 to state that none of this capacity should be imputed directly to PG&E.

c. Price of Northwest Power

PG&E differentiates the price of Northwest power on a seasonal basis. The reasoning behind this approach is that power will be cheaper during run-off months and more expensive during the summer, when the Northwest's hydroelectric systems are controlled. DRA differentiates on a daily basis, with cheaper power available at night and more expensive power during the day. DRA assumes that the Bonneville Power Administration, which markets much of the energy available from the Northwest, will set the price for energy sales at some percentage below PG&E's incremental energy costs.

PG&E argues that the day/night differential, which was adopted for use in last year's ECAC case, is more appropriate for short-term planning, when water conditions and the availability of hydroelectric power are better known. The seasonal approach works better for a longer term and for 1990 and beyond, when specific conditions are unknown.

The same logic underlies both PG&E's and DRA's proposals: power will be cheaper when it is more plentiful, and more expensive when there is greater demand for it. DRA's approach emphasizes the greater demand for power during the day, and PG&E's suggestion focuses on the variation in supply that occurs over the seasons.

We find little solid evidence to give us a basis for choosing between these proposals. We will adopt DRA's approach because it is consistent with our treatment of this issue in recent years, and because it appears to be supported by the behavior of sellers over the past few years.

d. <u>Capacity on the Intertie</u>

PG&E assumes that the Northwest Intertie will be fully loaded with contracted firm capacity and purchased spot capacity both for the test year and in the long term. DRA models the Northwest Intertie in the same way for the test year, but in the long term DRA assumes that the Intertie will not be fully loaded at night.

This issue surfaced only briefly and vaguely in the Comparison Exhibit. DRA's position, based on the limited description of this exhibit, appears illogical. Because it appears more logical, we will adopt PG&E's approach.

e. <u>Sales to Sacramento Municipal Utility District (SMUD)</u>

PG&E and DRA differ in one detail of their estimates of surplus energy available from the Northwest. PG&E includes estimates of sales from Pacific Power and Light to SMUD; DRA excludes the sales to SMUD. Because resource planning is based on PG&E's planning area, which includes SMUD's loads and resources, the sales from Pacific Power and Light to SMUD should be included in the estimates of the Northwest's surplus energy.

2. Capacity from QFs and Self-Generation

PG&E performed its own analysis of expected capacity from QFs and self-generation, rather than relying on the CEC's figures. Because PG&E believes that different economic factors determine the pace of QF development as opposed to the development of self-generation projects, its analysis shows increasing self-generation but little QF development after 1992.

TURN points out that under the assumptions of PG&E's current ECAC filing, PG&E has overstated the capacity from self-generation by 84 MW.

DRA relied on an analysis prepared by a consultant to the CEC. The CEC found both the utility's and its staff's forecasts to be "within a plausible range" (Exhibit 70, p. C-11), and it determined that the final forecast should split the difference between the two projections.

We will adopt the approach taken by the CEC in ER-7 and split the difference between DRA's (and CEC's staff) and PG&E's positions on this issue.

3. Generic Additions

PG&E's resource plan includes 2,700 MW of generic additions of baseload resources by 2007. Characteristics of these additions are assumed to be similar to those of a combined cycle plant, and the additions must meet cost-effectiveness tests to be included in the resource plan.

DRA objects to the inclusion of these resources, since the Commission's guidelines on resource planning have clearly excluded such "phantom" plants from resource plans.

We agree with DRA that the resource plan should not include generic additions. We have previously indicated that resources included in the plan should be committed or nondeferable, and we have accepted in this case the CEC's classification of certain resources as pending. Generic resources fit none of these categories, and should not be included in the resource plan for purposes of the general rate case.

4. Helms Pumped Storage Hydroelectric Plant

DRA derated the Helms facility by 395 MW because of the plant's poor reliability record during past peak periods. TURN supports DRA's recommendation because PG&E has not presented a consistent explanation of how it believes it overcame earlier problems.

PG&E presented testimony that equipment that will permit peak operation of all three units at the plant had been installed and was about to be tested. PG&E revised its spinning reserve requirements to reflect the greater capacity available because of the equipment. Thus, PG&E includes the full capacity of the Helms plant in its plan.

Although we would have preferred to have some indication about whether the equipment tested were successful, we will nevertheless accept PG&E's recommendation and include the full capacity of Helms in the resource plan.

5. Upgrades of Hydroelectric Facilities

PG&E includes 167 MW of upgrades associated with relicensing of its hydroelectric facilities. DRA opposes inclusion of these upgrades because PG&E made no showing of the cost-effectiveness of the improvements.

As PG&E points out, we have previously discussed the unique circumstances of the improvements connected with the relicensing of hydroelectric facilities (D.88-03-079). Among other points, we stated that the Federal Energy Regulatory Commission (FERC) reviews the cost-effectiveness of the improvements as part of the relicensing process, and we specifically determined that the sponsoring utility did not need to make a further showing of cost-effectiveness. The capacity upgrades should be included in the resource plan.

6. Rancho Seco

PG&E includes the Rancho Seco nuclear generating plant in its resource plan. DRA and TURN think Rancho Seco should be excluded from the resource plan.

Finding a satisfactory treatment for Rancho Seco is difficult. In June 1989, voters decided not to allow SMUD to operate the plant. Whether the plant will operate ever again is highly uncertain at this time. We agree with DRA that we should take into account the uncertainty surrounding future operation of Rancho Seco. For purposes of the long-term plan, the dependable capacity of Rancho Seco should be assumed to be 0 MW.

PG&E in its reply brief argues that removing Rancho Seco from the resource base assumes that PG&E will single-handedly make up the loss of Rancho Seco's capacity. PG&E makes a good point, but its recommendation--to keep Rancho Seco in the resource plan as a proxy for the resources that SMUD is likely to acquire to replace it--appears to us to assume an implausible opposite--that PG&E will supply none of the replacement capacity.

In the CEC's discussion of this issue in ER-7, it mentions that SMUD has capacity contracts with both PG&E and Edison that could be drawn on in the short term to replace Rancho Seco's capacity. The contract with PG&E has a minimum of 400 MW and a maximum of 1000 MW, and the contract with Edison ranges from 300 MW to 700 MW. (Exhibit 70, pp. 6-19--6-20.) As a conservative estimate of the amount of Rancho Seco's capacity that PG&E may be called on to replace, we will use the difference between the minimum and maximum amounts in its contract with SMUD. PG&E has an existing obligation to provide 400 MW to SMUD, regardless of the status of Rancho Seco, and it seems reasonable to assume that in the absence of Rancho Seco, SMUD would exercise its right to take an additional 600 MW from PG&E. Thus, the status of Rancho Seco should be reflected by reducing the resources available to PG&E by 600 MW.

7. **Conservation and <u>Load Management Forecasts</u>**

DRA notes that PG&E relies on the level of uncommitted DSM adopted by the CEC. The CEC has indicated that the level of savings associated with its recommendations is the minimum the utility should pursue. Because DRA has recommended higher levels of DSM funding than those underlying the CEC's recommendations, DRA suggests that the savings included in the resource plan should be those associated with the DSM funding adopted in this general rate case.

We agree with this point. As we discuss more fully in the section on DSM, the demand forecast should reflect net first-year savings of 51.7 MW of peak capacity and 408 GWh of energy.

8. <u>The Price of As-Available QFs</u>

In PG&E's base case submittal, as-available qualifying facilities (QFs) were assigned an average monthly price. PG&E states, without elaboration, that it uses "QF-in/QF-out pricing" for this resource. DRA prices as-available QFs at the marginal costs generated by the ELFIN simulations. DRA argues that its approach is logical because it allows the prices of these QFs to change as the resource plan changes.

The parties have offered little to illuminate their differences. We find PG&E's reference to "QF-in/QF-out pricing" confusing. The QFs-in/QFs-out runs are usually used in the ECAC cases to calculate the incremental energy rate (IER), although these runs also produce a marginal energy cost. The relation, if any, between the marginal energy costs resulting from these runs and the marginal costs used by DRA is not explained. We will adopt DRA's approach, because it was the only party to supply any rationale for its approach.

9. Fuel Price

DRA and PG&E differ in their projections of fuel prices, both for the test year and for the long term. Neither party devoted much explanation or argument to its position.

We will adopt DRA's projections for two reasons. First, DRA shows a convergence of the dispatch price and average price of gas, and this convergence is consistent with our resolution of a related issue, the treatment of gas demand charges, which we discuss more completely in connection with marginal energy cost. Second, DRA's average gas prices appear to be more reasonable than PG&E's.

C. Modeling Issues

1. Modeling Procedures

In several recent cases we have attempted to refine the ways in which production simulation models and their results are presented. Our goal has been to make the use of these models in our proceedings comprehensible even to those who are not familiar with the detailed workings of the various models.

In this proceeding, as we have discussed, parties using models presented two grounds for comparison: a run using the party's preferred model and a common set of assumptions and a run using a reference model--in this case, ELFIN--and the common data set. DRA notes that the scheduling of these submissions was such that it did not receive the final reference model base case until the day that its testimony was due to be circulated. DRA accordingly recommends that all in future cases, the following procedure be followed if the results of production cost models are in issue:

1. The utility files its resource plan based upon its preferred model and a similar resource plan using the reference model.

2. A workshop is held to define the base case resource plan.

3. The parties run the base case resource plan through all models used in the proceeding and explain the differences in results. (This step shows what differences in results are due to <u>model</u> differences.)

4. The parties provide a summary of the differences in modeling conventions that they would prefer over the reference model base case, and the changes in results that these differences make. (This step provides information on the differences due to <u>modeling conventions</u>.)

5. The parties state the resource assumptions in their preferred scenarios that differ from the reference model base case and summarize the results of these differences. (This step provides information on what differences the <u>resource assumptions</u> make.)

For general rate cases, DRA recommends that the initial step take place when the application is filed.

As we indicated earlier, the basic process was followed in this case. We agree with DRA that the steps it has outlined are the ideal way to clarify the issues connected with model runs. The primary problem encountered in this case had to do with the timing of the various steps. We will adopt DRA's recommended procedures as guidelines for the way issues relating to production cost models should be addressed, but we will grant the administrative law judge discretion to establish deadlines for these steps and to alter this procedure to fit the circumstances of a particular case.

2. <u>Modeling Conventions</u>

The goal of the production cost models is to simulate the operation of PG&E's system. But some simplification of the complexities of the operation of PG&E's system is necessary to provide the models information in a form they can use. Modeling conventions are some of the conversions or translations of information that modelers employ to make these simplifications. In addition to the different assumptions advocated by the parties, DRA and PG&E differ on some of these modeling conventions. Some of the differences in modeling conventions are closely tied to resource assumptions and have already been addressed. DRA's ELFIN runs differ from PG&E's reference model ELFIN runs in the following additional ways.

a. <u>Diablo Canyon Capacity Blocks</u>

PG&E models the Diablo Canyon nuclear power plant to be dispatched in two blocks of capacity; DRA uses four blocks. DRA states that its approach is consistent with the data from CEC's common forecasting methodology (CFM) proceeding. We will adopt DRA's approach.

b. <u>Rancho Seco Minimum Block</u>

As we discussed under resource assumptions, the Rancho Seco plant is currently shut down with little chance of restarting in the test year. We have already decided to exclude Rancho Seco from the resource plan and to make appropriate adjustments. It is therefore unnecessary to resolve the modeling difference raised by PG&E and DRA.

c. <u>Northwest Economy Energy Prices</u>

We have already discussed the parties' general differences in connection with their resource plan assumptions. The differences in modeling conventions are more specific.

PG&E uses a seasonal modeling approach. From March to June, the Northwest economy energy price is based on a heat rate of 7,000 MMBtu/kWh times the gas price; for all other months, the price is based on a heat rate of 8,000 MMBtu/kWh times the gas price. PG&E's prices are not adjusted for transmission line losses.

DRA varies its Northwest economy energy prices with the time of day. DRA used a heat rate characterization to tie prices to the dispatch price of natural gas. During the daytime, a system incremental heat rate of 10,000 Btu/kWh was assumed, and the nighttime assumption was 8,000 Btu/kWh. Economy energy was priced at 90% of the resulting value. DRA adjusts the dispatch price by a 4.5% dispatch loss factor.

DRA's pricing scheme has generally been followed in PG&E's recent ECAC case (see D.88-11-052, mimeo. p. 39; ALJ's Ruling of August 15, 1989 in A.89-04-001). We will also adopt DRA's approach in this case.

d. Monthly Load Shapes

DRA uses PG&E's load shapes for 1990, but relies on the load shapes used by the CEC in ER-7 for later years. PG&E uses its load shapes for all years.

In keeping with our reliance on many of the CEC's determinations in ER-7, we will adopt DRA's load shapes.

e. Spinning Reserve

DRA develops its spinning reserve requirements consistent with its position that Helms' capacity should be derated. PG&E includes all of Helms' capacity in arriving at its spinning reserve requirements.

We have accepted PG&E's position in the resource assumptions. Spinning reserve requirements should reflect all of Helms' capacity.

f. Dispatch Costs

PG&E develops dispatch costs for all generating units. The model uses these dispatch costs in choosing which units to use to meet demand, and these costs differ from the units' production costs. DRA derives dispatch costs for gas-fired units, but uses production costs for dispatch purposes for all other types of generation. DRA believes that production costs, rather than artificially derived dispatch costs, should be used in the models for these generation units.

We agree that production costs present a more accurate picture of the system's operation, and we endorse DRA's position.

D. Results

The results of the long-term resource planning exercise take many forms. In this case, the parties focused on the timing of the need for new generation resources. The other important result, the calculation of projected marginal energy costs, is addressed in a separate section.

PG&E concludes that expected generation from QFs, self-generation, and other committed resources are adequate to meet forecasted demand until 2003. Only in 2003 will PG&E need to add additional base load generating resources.

DRA agrees that PG&E has sufficient resources to meet expected demands for the near future, and that no PG&E-owned additions are proposed for the test year cycle. DRA forecasts a drying up of surplus capacity in the early 1990s, which suggests an earlier need for capacity than forecasted by PG&E.

TURN did not perform a full modeling of PG&E's system, but it finds PG&E's resource assumptions overly optimistic. TURN thinks PG&E has overstated the likely availability of a number of resources, a conclusion that also suggests an earlier need for additional resources.

ERA's general view is that PG&E has overstated the resources that it will have available to it. If generic, speculative resources and nonexistent resources like Rancho Seco are removed from the resource plan, ERA believes PG&E may need capacity as soon as 1990. In meeting this need for new capacity, ERA argues that no resources should have a reserved place in the resource plan. Demand-side and supply-side resources should be allowed to compete on an equal basis. ERA feels that demand-side management and solar and wind-powered generation resources will do well in this competition.

The parties agree that this case is not the appropriate forum to determine PG&E's need for new resources. The assessment of the need for new resources will be performed in the Biennial

Resource Plan Update proceeding, and the resource plan used in the general rate case is not precedent for or binding on the resource plans developed in the BRPU. In the general rate case, however, the parties' perceptions of the need for new resources colors their positions on demand-side management, RD&D, and marginal energy costs.

VI. Energy Reliability Index

The ERI serves several functions in the general rate case, including modifying the marginal generation capacity cost, deriving demand charges, and developing certain elements of revenue allocation and rate design.

Calculation of the ERI compares the utility's target reserve margin with the reserve margin resulting from forecasts of the utility's demand and resources for individual years. The primary elements of this comparison are the forecast of demand, the forecast of available resources, and the target reserve margins. These elements are closely related to long-term planning issues, and only PG&E and DRA made complete presentations on ERI issues.

A. Demand Forecast

All concerned parties agreed to use the demand forecast developed by the CEC for ER-7 (See Exhibit 138, pp. 3-4; Exhibit 70, App. D).

B. Target Reserve Margin

The parties now agree that the CEC's adopted target reserve margin of 17.5% should be used, although DRA argues that using this figure requires some adjustments to certain resource assumptions. DRA's positions are discussed and resolved in the following section.

C. Other Issues

1. The Effect of D.89-06-048

a. Positions of the Parties

Initially, the main differences between PG&E and DRA concerned the forecast of available resources, as we have mentioned in our discussion of long-term planning. In the ERI equation, PG&E used a floor of 0.2, while DRA used 0.4.

After the testimony on ERI issues had been completed, we issued D.89-06-048. This decision adopted a formula for calculation of the ERI that differs slightly from the one PG&E and DRA used in their testimony. PG&E submitted late-filed Exhibit 83 to present its revised ERIs, and DRA commented on PG&E's approach in its opening brief.

D.89-06-048 made three changes that affected the parties' recommended ERIs. First, it chose an exponential, rather than a linear, formula, a change that slightly altered the parties' ERI values for some years. Second, it adopted a floor value of 0.4, which doubled PG&E's figures from its assumed floor of 0.2 for several years. Third, it required use of the target reserve margin the CEC adopted in ER-7, which was not issued until late June, well after the close of hearings on this issue. ER-7's target reserve margin of 17.5% differed substantially from the target reserve margins of ER-6, which had been the basis for the parties' testimony. For example, the ER-6 target reserve margin for 1990 was 22.6%.

Use of the 17.5% target reserve margin of ER-7 also created another issue between the parties. DRA believes PG&E's attempt to calculate the ERI as directed in D.89-06-048 contains an inconsistency. DRA argues that the sizable reduction in target reserve margins from ER-6 to ER-7 resulted from a change in the CEC's approach to calculating the dependable capacity of oil- and gas-fueled generating units. In ER-7, the CEC decided to take into account the age of these plants and to "apply a statistical approach to help predict the availability of capacity from older oil and gas plants...." The resulting "age-derated" capacity of plants in PG&E's service area was reduced by a cumulative total of 489 MW by 1992 (Exhibit 70, pp. 4-29--4-30).

DRA believes it is necessary for consistency and accuracy to incorporate these age-deratings in calculating the ERI if the corresponding target reserve margin of 17.5% is used.

DRA also criticizes PG&E's assumption that the transmission lines to the Northwest are filled with capacity. DRA contends that the 17.5% reserve margin considers the reliability benefit of capacity support over the interties, so that including this transmission line as a resource amounts to a double-counting of its reliability benefit.

PG&E resists DRA's contentions. PG&E urges that the age-derating of oil and gas units is just one of many resource decisions made by the CEC, and DRA's focusing on it is just an attempt to increase the ERI artificially. The reliability benefits of the intertie to the Northwest have been included in the assumptions of dependable capacity that are used in the calculation of reserve margins. PG&E rejects DRA's argument that this is double-counting and points out that the CEC stated that it would have lowered the target reserve margin even more if it had taken into account more of the available low-cost capacity from the Northwest.

b. Discussion

We have already discussed our resolution of some of the resource-related disputes between DRA and PG&E in the section on long-term planning. On the question of the age-derating of capacity, we agree with DRA that the capacity assumed for these resources should be adjusted to reflect these age-deratings that contributed to the decision to lower the target reserve margin to 17.5%. Logic suggests that a more conservative estimate of the reliable capacity associated with these aging plants is directly linked to the decision to plan for less of a cushion between demand and supply.

We do not agree with DRA, however, that including the capacity associated with the Northwest transmission lines to the extent that we have in our resource decisions amounts to double-counting of this capacity, and we will not alter our previous determination or require an adjustment to the components of the ERI calculation.

2. Treatment of Rancho Seco

DRA calculates ERIs both including and excluding the Rancho Seco nuclear generating plant in the forecasted resources for PG&E's planning area. TURN also thinks Rancho Seco should be excluded from the resource plan and the calculation of the ERI.

We have already decided on the appropriate treatment of Rancho Seco in our discussion of resource assumptions. The same treatment should carry through to the calculation of the ERI.

D. Conclusion

The ERIs resulting from the determinations of this decision are shown in Appendix H. The use of these values will be discussed as this question arises in other areas.

VII. Marginal Costs

Marginal costs are the change in total costs resulting from a small change in a specified element of the utility's operation. The general rate case considers three general types of marginal costs. Marginal capacity costs measure the costs that change with changes in kilowatts of peak demand. Marginal energy costs vary with changes in kWh of energy. 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.

Economic theory teaches that prices should reflect marginal costs. With numerous adjustments for the quirks of the regulation of monopolies, we attempt to follow this principle.

A. Adjustments to Marginal Capacity and Customer Costs

Two parties propose undisputed adjustments that affect the final levels of marginal capacity and customer costs.

DRA recommends an adjustment for franchise fees and uncollectibles (FF&U). No one opposes this recommendation, and we will adopt it.

TURN points out that the general plant loading factor (GPLF) used by PG&E improperly included costs related to gas distribution. The GPLF must be adjusted for use in electric marginal costs. PG&E and DRA have accepted TURN's correction, and we will adopt the revised factors of 9.21% for marginal distribution capacity and customer costs and 3.69% for marginal transmission capacity costs, as well as PG&E's original factor of 2.10% for marginal generation capacity costs.

B. Marginal Capacity Costs

Marginal capacity costs are calculated at the generation, transmission and distribution levels.

1. Marginal Generation Capacity Costs

a. Cost of a Combustion Turbine

Marginal generation capacity costs are the generation-related costs that are incurred when load increases incrementally. The cost is expressed in $/kW-yr. For several years we have used the costs of a hypothetical combustion turbine as a proxy for marginal generation capacity costs. PG&E and DRA agree that the annualized cost of a combustion turbine results in an estimate of marginal generation capacity costs of $55.69/kW-yr., and we will adopt this base figure. With the adjustment for FF&U, marginal generation capacity cost is $56.17/kW-yr.

b. Adjustment for the ERI

(1) Introduction

One of the most hotly contested issues in this case concerned whether, for purposes of revenue allocation and rate design, marginal generation capacity costs should be multiplied by the ERI to reflect the relation of forecasted reserve margin to the target reserve margin. This issue arises, of course, only when the ERI is less than 1.0, when the utility has more than the needed capacity to meet its target reserve margin.

(2) Positions of the Parties

The parties took a variety of positions on this issue. Since this issue is, at its core, a question of how to define marginal costs, the terms of the argument were usually those of economic theory.

(a) DRA

DRA argues strenuously that marginal generation capacity costs should be adjusted to reflect excess generation. DRA advocates use of a six-year average ERI to make its recommended adjustment. DRA believes that the resulting marginal cost will provide price stability and accurate long-term price signals. Six years is long enough to approximate the utility's planning horizon and to yield a stable result. This period also corresponds to two general rate cases and three Biennial Resource Plan Update proceedings.

DRA summarizes the economic justification for its position:

> "Marginal generation capacity costs are approximated by the cost of a combustion turbine generator when the planning reserve margin is just met and there is neither an over nor under-supply of generation capacity....In a period of substantial excess capacity, the market price for capacity will fall below its long-run equilibrium value." (Ex. 113, pp. 2-4--2-5.)

DRA thinks it illogical to expect PG&E to pay the full cost of a combustion turbine for additional capacity when it has excess capacity, but such a course of action is consistent with not adjusting marginal costs by the ERI. The role of marginal cost in communicating underlying costs to customers is also reduced during times of excess capacity. In addition, economic theory holds that customers will not pay more for a good or service than the value of that product to them. In times of excess capacity, the value of additional generation capacity is diminished, and prices should reflect that diminution in value.

DRA also argues that in times of excess capacity, a utility may be able to add resources at less than the price of a combustion turbine. For example, it may be cheaper to return a retired plant to operation than to purchase a new combustion turbine.

(b) PG&E

PG&E agrees with DRA that it is appropriate to use the ERI to adjust marginal generation capacity costs for ratemaking purposes. The Commission has consistently used an ERI adjustment since the 1987 general rate case, and this policy was affirmed in the decision adopting a new ERI calculation method, D.89-06-048. The opponents of this adjustment have not presented any good reasons for the Commission to change its policy.

PG&E believes that prices should communicate short-run capacity costs to customers, and this reasoning underlies its recommended use of a three-year average ERI in this case, rather than the six-year average supported by DRA.

(c) CMA

CMA opposes using the ERI to lower the marginal generation capacity cost during periods of excess capacity. Economic theory argues that the full marginal cost should be used when cost is the issue, although CMA acknowledges that adjustments could be made to reflect the lesser value of capacity during periods of excess capacity. Thus, the ERI may conceivably have a legitimate role in setting the prices paid to QFs for sales of capacity to the utility, but for ratemaking issues, such as revenue allocation and rate design, CMA argues that no modification of full marginal cost is appropriate.

If the Commission decides to use the ERI to adjust marginal generation capacity costs, CMA urges it also to use conservative load and resource assumptions, as DRA has, and to apply the six-year average advocated by DRA, rather than the ERI for the test year.

(d) <u>CLECA</u>

CLECA also opposes using the ERI to modify marginal generation capacity costs. Reducing the full cost of a combustion turbine ignores the "lumpiness" of additional resources and assumes an ideal world where just enough generation can be constructed to meet demand. In addition, CLECA argues, "customers should receive a signal through revenue allocation and rate design that their creation of demand for electricity at times of the day and year which place pressure on the utility's ability to supply power will, in the long run, require the acquisition of new generation resources at a cost to the utility and its ratepayers." Thus, CLECA believes that PG&E's emphasis on short-run consumption signals is misapplied to generation capacity costs, and even the six-year average proposed by DRA is shorter than the useful life of much energy-using or energy-saving equipment that customers purchase in response to rate signals. CLECA opposes use of the ERI to adjust marginal generation capacity costs, but, if the Commission decides to accept this approach, CLECA supports an ERI of 1.0.

(e) <u>FEA</u>

FEA also opposes applying the ERI to adjust marginal generating capacity costs. FEA argues that the concept of this application is invalid, because it combines an assumption of short-term excess capacity (an ERI of less than 1.0) with an assumption of long-term equilibrium between supply and demand (the combustion turbine proxy for marginal generation capacity additions). These two assumptions are inconsistent, and this use of the ERI is unsound. FEA explains how a consistent approach to excess capacity could be developed:

> "If PG&E were planning to bring on a base load unit, for example, in the year 2000, it would be appropriate to cost that unit at the cost per kW of bringing it on-line in the year 2000 and discounting the cost of that unit back to present value. In that way, the current excess capacity would be reflected in the amount of years discounted and the date the unit is brought on-line." (Reply Brief, p. 5.)

FEA also argues that the formula for calculating the ERI is arbitrary and that using it to develop marginal generation capacity costs creates unstable rates as it varies from rate case to rate case. The Commission should reject this use of the ERI, according to FEA.

(f) Industrial Users

For similar reasons, Industrial Users also reject using the ERI to modify marginal generation capacity costs. Industrial Users cite FEA's witness' summary of his theoretical concerns:

> "Within the context of the theory of marginal cost pricing, it is appropriate that these costs be expressed in today's dollars, and without adjustment for any excess capacity that may exist, since the objective of the costing exercise is to determine what it would cost, in a marginal sense, to serve additional load today for a system in equilibrium (i.e., without excess capacity).... The ERI concept...mixes a consideration of

> actual system conditions (excess capacity), with marginal cost theory which essentially assumes (with respect to all cost elements) the existence of a system in equilibrium, without excess capacity. Mixing the two concepts produces a result that is a reflection of neither marginal costs, nor of actual system costs and conditions. As such, it has no theoretical validity." (Exhibit 234, pp. 4-5.)

Industrial Users also point out that the ERI calculation is extremely volatile, as demonstrated by the complete range of values advocated in this case, and is sensitive to relatively minor changes in resource assumptions. This volatility becomes dangerous when the ERI is applied to marginal costs and revenue allocation, because these changes can reallocate tens of millions of dollars, according to Industrial Users.

If the Commission decides to use the ERI to adjust marginal costs, Industrial Users believes that DRA's recommendation is based on a sounder analysis of PG&E's resources.

(g) ACWA

ACWA believes an ERI of 1.0, the equivalent of the unadjusted cost of a combustion turbine, should be used for revenue allocation.

(h) TURN

TURN is concerned that a short-run ERI will lead to rate fluctuations and distortions. TURN therefore advocates use of a 15-year levelized ERI to reflect the long-run prospect for generation capacity. The result of TURN's formula is very close to DRA's recommendation, and if the Commission adopts DRA's resource recommendations, TURN would support DRA's ERI proposal.

(3) Discussion

Several parties have raised questions about the use of the ERI to adjust marginal generation capacity costs. Responding to these concerns requires a focus on the function the ERI is intended to serve.

The ERI was originally developed as a way to adjust the capacity prices paid to QFs to reflect the value of the additional capacity supplied by QFs to the utility's system. When the system has excess capacity, it does not make sense to pay the full price of a combustion turbine, because the system does not need a combustion turbine at that time. On the other hand, we have recognized that added capacity always has some value, if only to improve the reliability of the system (D.82-01-103, 8 CPUC 2d 20, 64-65). The ERI was developed to offer a way of reflecting the value of additional capacity to the system over a range of relationships between resources and demand.

The point here is that the ERI's primary function is to measure the value of additional capacity. When the value of added capacity is the important concern, use of the ERI is appropriate. Adjusting short-run capacity prices paid to QFs is an excellent illustration of the proper application of the ERI.

However, as many parties have pointed out, it is not immediately obvious that the ERI should be used when the important consideration is cost. Marginal cost theory requires reliance on the full marginal cost of a particular item, and we have not usually attempted to adjust the costs, for example, of transmission equipment because there may be excess capacity on a particular transmission system.

The real issue here seems to be whether or not the combustion turbine is an adequate proxy of marginal generation capacity costs during times of excess capacity. When we first adopted the combustion turbine as a proxy for generation capacity costs, we tried to determine what resource the utilities would rely on if they were faced with a sudden shortage of peaking capacity. The combustion turbine proxy was developed as a measure of shortage costs (see D.81-01-103, 8 CPUC 2d 20, 52; D.93887, 7 CPUC 2d 351, 482-484), and the combustion turbine was assumed to be "the least capital-intensive addition to capacity to avoid a shortage" (D.93887, 7 CPUC 2d at 483). If marginal costs should be defined as how a utility would respond to shortages of certain types, then it appears that the validity of the combustion turbine as a proxy for marginal cost is unaffected by current excess capacity, since the concept is hypothetical by definition: if there were a shortage, this is how the utility would respond, with these costs. If, on the other hand, the existence of excess capacity makes it possible for a less expensive alternative to supply additional capacity and to serve as the measure of marginal generation capacity cost, then marginal cost should be less than the cost of a combustion turbine, as PG&E and DRA suggest.

Based on the theory of marginal costs, several parties argue that for purposes of revenue allocation, no adjustment should be made to the combustion turbine proxy as the measure of marginal generation capacity costs. These parties stress that the combustion turbine is assumed to be the cheapest source of pure capacity, and to argue, as DRA and PG&E essentially have, that 0.4 of a combustion turbine could be installed is obviously wrong.

These parties' arguments have two unspoken assumptions. First is the assumption that the marginal generation capacity cost should reflect the costs of capacity over the very long term. But the combustion turbine is a short-run measure that should not unthinkingly be used as a measure of long-term marginal costs. In any event, taking the very long view and ignoring foreseeable surpluses in capacity would result in ratepayers paying more for peak capacity than is justified by the system's circumstances.

Second is the assumption that the combustion turbine is the source of additional generation capacity, rather than just a proxy useful for estimating shortage costs. We think an ERI of less than 1.0 signals that resources other than the combustion turbine may be the sources of marginal generation capacity. The obvious example of this is capacity supplied by QFs. Payments for capacity supplied by QFs are based on the combustion turbine adjusted by the ERI, and the utility may reasonably be assumed to rely on such QFs for marginal generation capacity, rather than to install a combustion turbine. 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 to reflect lower-priced sources of marginal generation capacity is also consistent with the conception of the combustion turbine as the maximum shortage cost.

Some parties have criticized the ERI for its volatility. We share these parties' concern that this volatility is undesirable when it affects rates. Taking the six-year average ERI suggested by DRA for use in revenue allocation and rate design provides not only rate stability, but also a reasonable balance between long-run and short-run assessments of the need for and cost of generation capacity.

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 BRPU proceeding will likely be the primary source of future series of ERI projections.

We conclude that it is appropriate to adjust the full annualized cost of a combustion turbine of $56.17/kW-yr. by the six-year average ERI of 0.418 to develop the marginal generation capacity cost of $23.48/kw-yr. used for revenue allocation and rate design in this proceeding.

2. Marginal Transmission Capacity Costs

Marginal transmission capacity costs reflect the cost of serving an additional kW of demand at the transmission system's peak.

DRA and PG&E agree that this cost should be calculated by referring to data on demand-related transmission additions and load growth for ten historical and five forecast years. DRA also agrees with PG&E's basic estimate of these costs of $32.19/kW-yr., which includes DRA's recommended treatment of large transmission additions and TURN's proposals for changes to the general plant loading factor. DRA would add an adjustment for franchise fees and uncollectibles, and PG&E does not oppose this addition to its basic figures. TURN appears to support this resolution.

We will adopt $31.80/kW-year, the costs agreed to by PG&E and DRA, as the marginal transmission capacity costs.

3. Marginal Distribution Capacity Costs

Marginal distribution capacity costs are the costs required to serve an additional kW of peak demand on the distribution system. There are two components, corresponding to the primary and secondary distribution systems. The distribution system performs both a capacity or demand-related function and a customer access function. Demand-related costs are allocated to marginal capacity costs, and costs required to provide a customer with access to the system are allocated to marginal customer costs. The distinction between these two functions is not clear, since the same equipment can serve both functions, particularly at the secondary distribution level. Allocating costs between these functions can become controversial, and the disputes about this allocation are addressed in the discussion of both marginal capacity and marginal customer costs.

a. Marginal Primary Distribution Capacity Costs

The primary distribution system includes substations, towers, poles, and primary conductors.

Both DRA and PG&E treat primary distribution costs as demand-related costs. DRA and TURN have accepted PG&E's final estimate of $52.54/kW-yr., which includes DRA's adjustment for customer contributions and reflects recent changes in FERC's allocations of certain equipment between the primary and secondary distribution systems (see Tr. 58:6314-6315).

ACWA argues that marginal primary distribution costs should be differentiated between overhead and underground service. ACWA contends that the costs of providing underground service are about double the costs for overhead service. ACWA recommends, for example, that the $52.54/kW-yr. figure advocated by DRA and PG&E should be broken up into a overhead cost of $39.80 and an underground cost of $79.60.

CFBF supports ACWA's position on differentiating between overhead and underground installations. In addition, CFBF argues that the Commission should also distinguish retrofits caused by the encroachment of urban and suburban areas into areas that were formerly primarily agricultural. CFBF submits that the increased costs caused by these retrofits--both the direct costs of the equipment and the shortened useful life of existing equipment--should be separately identified and allocated to the classes that are responsible for the need for the retrofits.

We will adopt a marginal primary distribution capacity cost of $53.00/kW-yr., which reflects FF&U adjustments to the basic figure of $52.54/kW-yr. recommended by PG&E and DRA. We acknowledge, as ACWA and CFBF urge, that overhead and underground costs are likely to differ, but we do not endorse the figures ACWA recommends. As PG&E pointed out, ACWA's figures are derived from ratios that PG&E developed for customer access equipment, and it is illegitimate to apply these ratios to demand-related equipment without further justification. The differential in distribution costs for overhead versus underground equipment may also be counterbalanced by differences in the length (and thus the cost) of distribution lines associated with overhead and underground facilities.

Similar complications make us reluctant to adopt CFBF's argument about retrofits of existing primary distribution facilities. In addition, CFBF did not present any evidence about the level of the costs that it would have us allocate to other classes.

These and other issues are currently under investigation at the instigation of the Legislature (Tr. 29:2981-2982), and we should not attempt to anticipate the results of that study at this time.

b. <u>Marginal Secondary Distribution Capacity Costs</u>

Equipment on the secondary distribution system includes final line transformers, secondary conductors, service drops, and meters. PG&E believes marginal secondary distribution costs have a demand-related component that should be reflected in marginal capacity costs. PG&E calculates this demand-related cost to be $6.81/kW-yr. DRA denies that any of the marginal secondary distribution costs are related to capacity; DRA views all marginal costs associated with the secondary distribution system to be customer-related.

PG&E argues that occasionally actual load growth on a distribution circuit can exceed forecasted load growth. In such instances, PG&E must make upgrades to the distribution system to meet the increased demand, even though the distribution equipment has not reached the end of its useful life. PG&E states that things like the introduction of new appliances can cause these problems, which are manifested in dimming of lights and similar effects. Whenever possible, PG&E seeks to identify the individual customer or customers who caused the unanticipated growth; for example, a customer who adds a swimming pool pump can be specifically identified. When increased demand can be tracked to a specific customer, PG&E will seek to recover its added costs through a facilities charge. However, in some instances, an unexpected increase in load cannot be attributed to a particular customer. PG&E views these upgrades as marginal secondary distribution capacity costs.

DRA thinks all marginal secondary distribution costs are customer-related. Part of determining the size of a distribution circuit, DRA argues, is anticipating load growth over the useful life of the equipment. Marginal costs should be based on modern equipment and customer consumption patterns, so any load growth that exceeds historical rates should be taken into account in the sizing and the costing of the marginal distribution equipment. Since a rational planner will not plan for unanticipated growth and for upgrades before the end of the useful life of the distribution equipment, DRA believes that as a matter of definition the cost of the upgrades described by PG&E are not marginal costs.

ACWA agrees with DRA that all marginal secondary distribution costs are customer-related costs. TURN thinks PG&E has not adequately supported its estimate of these costs.

This issue blurs the boundary between theory and practice. DRA has correctly stated the theoretically correct approach to marginal cost determination, but PG&E has pointed out a practical limitation to that theory. Sizing of a secondary distribution circuit involves estimates that are somewhat based on averages--average customer growth, average on-peak consumption, etc. Even a cautious approach to sizing distribution equipment will mean that peak demand on some circuits will exceed the reasonable expectations of planners. PG&E could size its distribution equipment so that upgrades were never needed, but that practice would result in unnecessarily expensive distribution equipment for nearly all secondary circuits. PG&E's marginal cost estimates could also be based on equipment that would never require upgrades, but that assumption would result in a distorted picture of PG&E's actual planning process.

We are most comfortable viewing PG&E's proposed marginal secondary distribution capacity costs as a measure of variance, of the extent to which planning secondary distribution circuits on the basis of averages results in some undersized circuits. If PG&E's explanation of the reasons for these upgrades is accurate, then these costs are properly classified as capacity costs, reflecting a growth in demand not related to growth in the number of customers. This figure should never become very large, because, as DRA points out, anticipated load growth should constantly be revised to reflect recent trends and experience.

For these reasons, we will accept PG&E's estimate of marginal secondary distribution capacity costs of $6.81/kW-yr. When adjusted for FF&U, the adopted cost is $6.87/kW-yr. We also agree with DRA that this figure should be examined in the next general rate case and that, as background to that examination, PG&E should perform a study on the expected need to upgrade modern distribution facilities because of load growth.

C. Marginal Customer Costs

Marginal customer costs are those costs incurred to establish and maintain customers on the electric system, and they include investments in distribution equipment needed to provide customers access to the system, operation and maintenance costs related to this equipment, materials and supplies, working cash capital, and customer accounting costs, such as meter reading, billing, and bookkeeping.

We will discuss some general issues before addressing issues related to the customer costs of specific customer classes.

1. General Issues

a. General Approach

In D.86-08-083, we considered the issue of marginal customer costs and directed PG&E and DRA "to analyze nondedicated distribution equipment for access versus demand function" (mimeo. p. 52).

PG&E's response assumes that the primary function of the secondary distribution system is to allow the customer access to PG&E's system. PG&E consequently assigns the costs of the secondary distribution system, up to and including the final line transformer, to customer costs. PG&E gathered the costs used in its estimates from its Computer-Produced Estimating System (COMPRESS). PG&E uses COMPRESS to estimate the costs of field installations, and the COMPRESS data base includes the current prices for the facilities included in its customer costs.

Certain facilities, such as transformers, may serve customers from both the residential and small light and power classes. PG&E allocated the costs of such facilities on a pro rata basis.

DRA used a similar approach. DRA's initial criticisms of PG&E's approach were largely accepted by PG&E, and PG&E's final recommendations (Exhibit 84, p. 190; see Exhibit 16-B) incorporate many suggestions offered by DRA and other parties.

We find the general approach followed by DRA and PG&E to be reasonable, and we elaborate on some of the details of this approach and on remaining differences in the following sections.

b. TURN's Corrections

TURN also pointed out that the estimates of customer accounts and collections costs included three different errors totaling about $16,500,000. PG&E and DRA have accepted these corrections and incorporated them into their revised marginal customer cost estimates. We agree with TURN that these costs were improperly included in PG&E's initial figures.

c. Secondary Distribution O&M Costs

DRA allocates all of the O&M costs related to final line transformers, secondary conductors, service drops, and meters to customer-related costs, consistent with the classification of secondary distribution costs mentioned in the discussion of the general approach. PG&E allocates a portion of these O&M costs to demand-related costs.

We have previously determined that a small portion of marginal secondary distribution costs should be allocated to capacity. It follows that a proportionately small part of secondary distribution O&M costs should be allocated to capacity. The remainder and the bulk of these O&M costs should be allocated to marginal secondary distribution customer costs.

2. Marginal Customer Costs for Specific Customer Classes

a. Residential, Agricultural, and Small Light and Power

PG&E initially proposed to use the cost of new business to estimate customer costs. This approach looks at the current costs of connecting customers to the system. DRA pointed out, however, that for many customer classes, this approach would lead to great distortions. Many new residential customers, for example, are served through underground facilities, but many existing customers have less expensive overhead service. DRA argued that many different features of the standing stock of facilities amount to different services, even within the same customer class. Examples of these different services include underground versus overhead facilities, single versus multifamily dwellings, different transformer sizes, and single versus three-phase service. DRA believes the customer costs developed for the residential, agricultural, and small light and power classes, in particular, should reflect the existing composition of these distinctive services.

As a corollary to its standing stock approach, DRA adds a 3% vacancy factor to customer-related investments. This adjustment is appropriate, DRA believes, because at any given time, customer-related equipment is available and installed to serve more customers than those actually receiving service.

PG&E accepted DRA's points and revised its marginal customer costs accordingly. DRA and PG&E now agree that marginal customer costs should reflect the characteristics of typical installations in the standing stock of existing installations for the residential, agricultural, and small light and power customer classes. TURN, CFBF, and ACWA also support this position.

CMA argues that a true marginal cost should be derived from the current costs of a minimally sized distribution system as a measure of access-related (but not load-related) distribution facilities. CMA was unable to develop its own estimates of these marginal customer costs, but developed its recommendation from the analyses of DRA and PG&E.

As we understand the positions of the parties, the standing stock approach attempts to develop costs that reflect certain characteristics of the existing system. In particular, DRA developed cost distinctions between overhead and underground facilities, single and multifamily dwellings, different transformer sizes, and single and three-phase service for these customer classes. DRA believes these distinctions are valid for purposes of marginal cost pricing because they represent what a competitive market would treat as separate products. The costs that are applied to these different types of facilities are developed by applying a real economic carrying charge to current unit investment costs.

CMA's approach would attempt to develop for each customer class the minimum distribution investment needed to provide a customer with access to the system. All other distribution costs would be allocated to demand. The mix of facilities would reflect the equipment used in adding customers to the system.

CMA has attempted to portray the standing stock approach as contrary to marginal cost principles. As we understand the competing approaches, however, the standing stock approach is used only to develop the appropriate characteristics of customers within a class. The costs that are applied to these characteristics are based on a marginal cost approach, the application of a real economic carrying charge to current unit investment cost to develop a simulated rental value for the equipment. We have previously addressed similar issues in D.88-12-085, and we again conclude that use of the standing stock approach to develop the characteristics of customer costs is consistent with marginal cost principles. The standing stock approach supported by DRA and PG&E should used to develop investment costs for the residential, agricultural, and small light and power classes.

b. Medium Light and Power and Primary and Secondary Voltage Levels of Large Light and Power

PG&E's estimates of the marginal customer costs for the medium light and power class and the primary and secondary level of Schedules E-19 and E-20 are consistent with our decision to allocate the bulk of secondary distribution O&M costs to marginal customer costs. We will adopt PG&E's revised marginal customer costs for these classes, as shown in Exhibit 84, p. 190, adjusted for DRA's recommended vacancy factor and FF&U.

c. Transmission Level of Large Light and Power

PG&E based its estimate of transmission level customer costs for Schedules E-19 and E-20 on recorded data from 26 job estimates of transmission level customer connections. The estimates included the costs of dedicated transmission line extensions, which PG&E argues are necessary to provide such customers with access to its system. The resulting estimate is $118,832.37 per customer-year.

After other parties objected that the costs of dedicated line extensions do not reflect the costs of providing access to typical customers, PG&E supplied information on what its costs would be without such extensions. DRA supports this revised figure of $49,777.25 per customer-year, in lieu of its admittedly rough original estimate.

CMA criticized PG&E's original study because of the wide variation in individual job cost estimates--from $40,000 to over $1,000,000. CMA pointed out that the application of PG&E's line extension rules, which vary the payments required from customers depending on expected revenues, made PG&E's estimates unreliable. CMA supports DRA's original estimates (which DRA has now withdrawn) because the estimates excluded the costs of transmission facilities dedicated to specific customers.

CLECA also objects to PG&E's inclusion of transmission line extensions in its estimates of marginal customer costs. The size of a line extension depends on the customer's demand, and thus the costs of line extensions are inappropriate for a study of customer-related costs, according to CLECA. In addition, PG&E's study was flawed because it considered only 26 jobs, with a wide range of costs, over a period of 11 years, and the costs of earlier jobs were escalated without consideration of whether the escalated costs correspond to current marginal costs. In response to CLECA's questions, PG&E lowered its O&M and A&G components, but the revised marginal customer costs figures still include the costs of line extensions. CLECA supports DRA's original figure as being more representative of typical transmission level marginal customer costs.

We agree with many of the parties that the costs of customer line extensions should be excluded from the calculation of transmission level marginal customer costs. Although we continue to have reservations about the bases of PG&E's cost study, we will adopt the revised figure that arose from this study, $49,777.25 per customer-year, adjusted for FF&U, as a reasonable estimate of transmission level marginal customer costs. DRA now endorses this figure, and DRA's earlier estimate, which CMA and CLECA support, was based on a very rough estimate. The revised figure has the most support on the record in this case.

d. Streetlighting

PG&E contends that no marginal customer costs should be adopted for the streetlighting class. PG&E prefers, because of the complex combinations of PG&E versus customer ownership that permeate this class, to incorporate all customer-related costs in facilities charges for specific schedules. Because of the diversity of ownership arrangements within this class, PG&E believes that no average estimate of marginal customer costs can accurately reflect the characteristics of this class.

Cal-SLA argues that marginal customer costs should be adopted for those elements of the streetlighting rates that are customer-related and are common to all types of streetlights. These costs include the costs of accounting, billing, and transformers serving streetlights, according to Cal-SLA. Cal-SLA recommends that service connections should be treated as facilities-related, rather than as customer-related, because customers on Schedule LS-2 own their own service connections and are not charged by PG&E for this service. Cal-SLA excludes service connections because it believes only costs common to all types of streetlights should be designated as customer costs.

DRA is in partial agreement with Cal-SLA. DRA agrees that certain costs common to all streetlighting customers should be treated as customer-related. DRA appears to differ with Cal-SLA about the treatment of service connections. DRA's recommended treatment would depend on the ownership of the service connection. The service connections for customers on Schedule LS-1 are owned by PG&E, and their costs should be included in marginal customer costs. On the other hand, customers on Schedule LS-2 own their own service connections, and these costs should not be included in the calculation of marginal customer costs.

For purposes of marginal cost, we conclude that DRA's approach will most accurately reflect the marginal customer costs of the streetlighting class. PG&E's reliance on facilities charges, while administratively simple, ignores the common and clearly customer-related costs like billing and customer accounting. Cal-SLA's approach is very similar to DRA's, but it elects to treat the costs associated with PG&E-owned service connections like special facilities, rather than as customer-related costs, even though a substantial portion of the class receives service through PG&E-owned service connections. DRA's position is in some ways the flip side of Cal-SLA's, but it has the advantage of covering the common customer-related costs while excluding the costs associated with customer-owned service connections from the calculation of marginal customer costs for the class. This approach should come closest to reflecting the customer-related costs of this diverse class. We agree with PG&E, however, that the customer accounting costs developed in the streetlight facility cost study are more accurate than those used by DRA. The customer accounting costs of the streetlight facility cost study should be used to develop marginal customer costs for the streetlighting class.

D. Marginal Energy Costs

Marginal energy costs measure the change in the total operating costs of an electric generation system when the demand for energy changes incrementally or decrementally. Both PG&E and DRA submitted complete presentations on marginal energy costs, and TURN raised some issues concerning the details of the calculation.

1. Model Differences

Both PG&E and DRA base their presentations on marginal energy costs on the zero-intercept method and the results of production cost simulation models. PG&E's preferred model is PROMOD 27.9; DRA prefers ELFIN 1.7. Both parties concede that the choice of models had little effect on their eventual recommendations on marginal energy costs. PG&E, for example, states that when its preferred assumptions are used, the two models differ by only about 1.8% annually and 4.5% by rating period. The resource plans that underlie the assumptions appear to make much more difference than any differences in the models themselves. We conclude, as we have in other recent cases (e.g., D.88-11-052), that both models are acceptable for purposes of calculating marginal energy costs.

2. Gas Demand Charges

a. Positions of the Parties

One of the primary components of marginal energy costs is the forecasted cost of natural gas. No party disputes that natural gas will be PG&E's marginal fuel for a substantial portion of the test year. PG&E supports DRA's recommendation to use the commodity cost of gas to develop the marginal energy costs. The commodity cost is the price paid to gas producers.

TURN argues that using only the commodity cost understates the true cost of gas and the resulting marginal energy costs. The total cost of gas should also include demand and transportation costs in addition to the commodity cost. The demand charge is the cost of access to the gas pipeline and storage system, and the transportation charge is the cost of transporting the gas to the utility.

TURN believes that the premise behind DRA's position is faulty. DRA asserts that gas demand and transportation charges are not avoidable when gas consumption is reduced. These charges, however, have a forecasted component that varies with changes in the forecasted quantity of purchased gas, and all of the Tier 2 transportation charge is based on the volumes of gas being transported. Thus, it is possible to quantify changes in transportation and demand charges associated with changes in consumption of gas.

In every recent decision considering the proper gas price to use for calculation of marginal costs, the Commission has used an average cost of gas, sometimes represented by the utility electric generation (UEG) rate, according to TURN. TURN views DRA's recommendation as illogical and a departure from precedent.

TURN favors use of long-run marginal costs for revenue allocation and rate design because these costs give consumers the best information on the costs of conservation or consumption. But even if the Commission adopts short-run measures, it should include the demand and transportation costs to arrive at an accurate measure of marginal energy costs.

DRA responded to some of TURN's criticisms in its opening brief. DRA proposes an alternative approach that would view demand charges as avoidable over a six-year period, the same time frame DRA uses to evaluate the need for capacity in its ERI recommendation. In its alternative position, the average of the avoidable discounted demand charges from 1990 through 1995 would be included in the marginal energy cost calculation.

In its opening brief, ACWA proposed an approach similar to DRA's alternative. ACWA believes that long-run trends in the price of gas should be reflected in marginal energy costs. ACWA recommends that if the Commission accepts DRA's approach to marginal energy costs, it should adjust the resulting values for DRA's forecasted convergence between the marginal and average costs of gas by 1996. ACWA would accomplish this adjustment, which would apply for cost allocation purposes only, by reflecting one-half of DRA's current calculation of the difference between the average and dispatch costs of gas as a percentage of the average gas price over six years, beginning in 1990.

b. <u>Discussion</u>

It is apparent from the extent of the dispute on this issue that the question of how to define marginal gas costs under our new regulatory structure is still undecided. The gas utilities filed studies of marginal costs that were surprising in their diversity, and we have yet to face the definition of marginal costs for gas directly.

DRA's approach seems to be grounded in the notion that only those costs that vary on the margin during the test year should be considered in calculating marginal energy costs. This definition of marginal costs is too strict in light of our decisions on other components of the cost of gas.

As TURN pointed out, our decision on the costs that are avoidable by QFs, D.88-07-024, used a broader approach. In that decision, we determined that generation by QFs allowed the utility to avoid all of the components of the UEG rate except for customer costs. The transportation charge and the demand charge were deemed to be avoidable, because they were allocated on the basis of the volumes the utility, as a UEG customer, was forecasted to purchase. Decreases in the gas needs of the utility would be reflected in the annual allocation of these costs. Thus, for any period of more than one year, these costs would vary with the quantity of gas purchased.

We recognize the great differences between marginal costs and avoided costs (D.88-07-024, mimeo. p. 21; D.88-03-079, mimeo. pp. 21-34), and TURN's citation to precedent is not nearly as compelling as TURN portrays it. At the current time, however, it appears that the formula adopted for avoided costs in D.88-03-079 is the best available estimate of marginal gas costs for any period longer than the very short term. For the purposes of this rate case, we will define the gas portion of marginal energy costs to be identical to the definition of avoided costs in D.88-07-024: all components of the UEG rate except customer costs (See D.89-09-099, mimeo. pp. 17-21).

The formula adopted in D.88-07-024 was subject to many of the doubts that we still harbor about the accuracy of the adopted approach, and the method we adopted then was designated as an interim method. We stated in D.88-07-024 our desire to revisit this issue when we had completed our analysis of marginal costs. Although our analysis has been delayed somewhat, this conclusion also applies in this case, and with added emphasis because our express purpose is to define marginal energy costs. Thus, the method we adopt here should also be considered interim and subject to revision when we develop better approaches to defining marginal costs for natural gas.

3. <u>NOx Adder</u>

a. <u>Positions of the Parties</u>

TURN proposes that the marginal energy cost calculation should reflect the cost to society of the oxides of nitrogen (NOx) produced by power plants that burn fossil fuels. Expressing these costs as an "adder" to marginal energy costs also quantifies the societal benefit of reducing NOx emissions, according to TURN. If the price of electricity more accurately reveals the societal cost of generating power, consumers will be better able to chose to consume or conserve electricity.

TURN relies on the theory of revealed preferences to quantify the costs of NOx. Under this theory, the value of reducing pollution is assumed to be at least as great as the costs of controls to reduce the emissions. TURN bases its estimate on certain standards developed by appropriate air quality management districts and the best available technology to meet those standards. The resulting figure, $18,800 per ton of NOx reduction, is then related to production at PG&E's power plant to arrive at a total change in NOx emissions, which is then distributed on a cents per kWh basis.

PG&E opposes TURN's proposal on several grounds. First, PG&E contends that TURN's proposal requires the Commission to break with its precedent and to recognize as a marginal cost a cost that is not actually incurred by PG&E in operating its system. Second, PG&E believes that a piecemeal consideration of the external costs of producing electricity would be distorted. (External costs or externalities are societal costs not directly reflected in the price of a good or service.) Third, TURN's proposal could have unintended effects, such as encouraging industries to move to areas where no such adder was in effect.

DRA also opposes TURN's proposal. DRA is concerned that consideration of only the NOx externality would interfere with a more comprehensive consideration of externalities that has been scheduled in connection with the Biennial Resource Plan Update proceeding.

CMA rejects TURN's proposal because it believes that adding one external cost to marginal energy costs while holding the total revenue requirement constant merely distorts rate design without sending ratepayers any economic signal about the cost of reducing NOx emissions. Thus, TURN's proposal results in a rate design that reflects less of the utility's internal costs of production without the economic communication to ratepayers that TURN has cited to justify its proposal. Because the external cost of NOx reduction is not added to rates, TURN's proposal merely has the effect of increasing marginal energy costs and directly reducing other elements of PG&E's marginal costs. The costs of NOx reduction is not internalized, and TURN's proposal merely shifts costs from one customer class to another, according to CMA.

FEA also rejects TURN's proposal. TURN has not adequately explained why the Commission should take this unprecedented step. In addition, the specific proposal TURN presented improperly assigns fixed costs to variable energy costs. FEA concludes that the proposal has numerous deficiencies and should be denied.

b. <u>Discussion</u>

TURN has presented an interesting proposal for integrating some of the external costs associated with generating electricity into our ratemaking process. However, we share the concerns of some of the parties that focusing on only one specific externality will be unbalanced and will lead to distorted rates.

CMA points out that constructing new generating plants or new transmission and distribution lines also has external costs, and focusing on only one element of marginal cost while ignoring others leads to distortion in the cost relationships among all the marginal cost components. Even if we narrow our focus to the element, generation, that is the subject of TURN's proposal, it is obvious that the generation of electricity has many external costs and benefits associated with it. We prefer to take a more complete view of these various influences before incorporating them into the details of revenue allocation, as TURN urges.

CMA makes another important point. By incorporating the external cost of NOx emissions in marginal energy costs, TURN's proposal accomplishes only the shifting of costs among the various marginal cost elements. The external cost TURN purports to identify is not passed on directly to consumers, and the element of communication that TURN cites as justification for its proposal is extremely diluted.

As DRA points out, we have scheduled a consideration of externalities in connection with the BRPU proceeding (I.89-07-004), and the CEC will also be considering the value of reduced emissions of air pollutants from utility plants over the next year. We prefer to wait for the results of these investigations and until we have a more complete picture before we integrate these considerations into rates. We therefore will not adopt TURN's proposed NOx adder.

E. Conclusion

Our adopted marginal costs are set forth in Appendix H.

VIII. Revenue Allocation

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, as we have just discussed. 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. During interclass revenue allocation, we determine the cost of providing services to each customer class and derive each class' proportionate responsibility for contributing to the utility's overall revenue requirement.

Interclass revenue allocation has two basic steps. First, marginal costs for various services are assigned to the classes in proportion to the demand each class has for the particular service. Next, this marginal cost-based revenue responsibility is adjusted to fit the exact revenue requirement that we developed in the results of operation section of this proceeding and in related proceedings. We will address the issues related to these two steps in order.

In this decision, we address the revenue allocation and rate design for only PG&E's electric operations. Revenue allocation and rate design for PG&E's gas operations are considered in its Annual Cost Allocation Proceeding (ACAP).

In this proceeding, PG&E proposes to split the existing large light and power class into two new classes. The new E-20 class is for customers with maximum demands of 1,000 kW or more and includes Schedules E-20, E-24, E-25, A-RTP-20, S, and special contracts with large customers. The new class E-19 covers customers with maximum demands of 500 to 1,000 kW and includes Schedules E-19, A-RTP-19, and S. PG&E's proposal was unopposed, and revenues will be allocated separately to these new classes.

A. Use of Marginal Costs in Revenue Allocation

1. Introduction

After marginal costs are developed, they are allocated to the customer classes and schedules according to the costs that the class or schedule imposes on the system. The parties largely agree on basic principles of how to allocate the marginal costs we have developed to the customer classes.

Marginal energy costs are attributed to a class or schedule according to the daily and seasonal time of use energy consumption for the particular group of customers under consideration. Marginal customer costs are assigned to the class or schedule according to the number of customers in the group.

The allocation of marginal capacity costs is more complex. Marginal capacity costs are allocated to various customer groups based on the group's level of coincident and noncoincident demand. Coincident demand refers to the amount of demand a customer or group of customers places on the system at the time of the system's peak demand. Noncoincident demand refers to the customer's or group of customers' highest level of demand, which may not coincide with the time of the system's peak.

Because different portions of PG&E's system are sized to meet different functions, marginal capacity costs are allocated to match those functions. For example, with the exception of ACWA and CFBF, the parties agree that the generation system is designed to meet peak demand, and marginal generation capacity costs are therefore allocated entirely according to the customer group's level of coincident demand. A particular secondary distribution system, on the other hand, is sized nearly entirely to meet the highest demand of the customers it serves, regardless of when that demand occurs. The marginal costs of secondary distribution are therefore allocated on the basis of the customer group's level of noncoincident demand.

Allocations of marginal transmission and primary distribution capacity are not so straightforward. The transmission system is primarily built to meet peak demand, but a portion of the transmission system is sized also to meet the noncoincident demands customers place on the transmission system. The primary distribution system is sized mostly to meet the noncoincident demand of the customers on a particular distribution system, but coincident demand also plays a large role selecting the equipment for these distribution systems. The exact allocations of marginal transmission and primary distribution capacity costs according to coincident or noncoincident demand were issues in this case.

2. <u>Calculation of Class Coincident Demands</u>

DRA recommends that class coincident demands for 1990 should be estimated using historical load factors derived from 1985, 1986, and 1987 load data, weighted by PG&E's hourly generation loss of load probability (LOLP) forecasted for 1990. DRA also recommends that each class' hourly loads for each of the historical years should be scaled so that multiplying each year's hourly percentage times PG&E's expected system loads for the test year produces the test year's sales forecast. DRA states that this correction is necessary to overcome implicit assumptions that new customers have the same usage characteristics as existing customers and that 1987, a drought year, was typical. To adjust the resulting system demands to get the expected 1990 system peak, DRA recommends scaling up the coincident demands by a factor equal to the forecasted 1990 system peak demand divided by the 1990 LOLP-weighted system peak demand. This adjustment is necessary because LOLP-weighted average demands are the average of several hours of system demands, and only the hour with the highest demand is the system peak. The average will therefore be lower than the actual system peak, and use of an unadjusted average will underallocate marginal capacity costs.

PG&E agrees with DRA's recommendations, and we will adopt them.

3. <u>Allocation of Marginal Generation Capacity Costs</u>

ACWA argues that marginal generation capacity costs should be allocated based on a combination of coincident demand and daily cycling capacity. Daily cycling capacity is a measure ACWA developed to express the notion that a portion of marginal generation capacity costs is caused by daily load fluctuations as the customer classes increase, then decrease, their loads. ACWA contends that this daily cycling increases O&M costs and decreases a powerplant's useful life.

ACWA quantifies the daily cycling capacity cost as $4.14/kW, derived from DRA's and PG&E's showings on O&M cost. When this figure is multiplied by the LOLP-weighted coincident demand, the result is a total daily cycling cost of $48,900,000. This total cost is allocated to the customer classes at the rate of $11.01/kW of daily cycling cost.

DRA opposes ACWA's proposal. DRA argues that ACWA failed to take into account the many factors, other than daily cycling, that can affect O&M costs, and ACWA has presented no method of separating the variable O&M costs due to cycling from those resulting from steady operation of a generating unit.

ACWA's proposal has not been adequately supported in this proceeding, and we will not adopt it. We will allocate marginal generation capacity costs entirely on the basis of coincident demand, as other parties suggest.

4. Coincident and Noncoincident Shares of Transmission and Primary Distribution Capacity Costs

a. DRA's Proposal

DRA recommends adjusting noncoincident demands for the residential and small light and power classes to reflect the diversity of individual customers' demands at the final line transformer. Noncoincident demand for a group of customers is usually determined by adding up the maximum demands of those customers, regardless of when that demand occurs, and is measured by the load on the final line transformers. For the residential and small light and power classes, however, the final line transformer serves more than two customers, and it is unlikely that the customers' demands will all peak at the same time. Thus, the diversity of the customers' maximum demands should be reflected in the noncoincident demand as measured at the final line transformer.

DRA criticizes PG&E's approach, which developed a measure of diversity called the transmission area load, the sum of maximum demands on its transmission substations. DRA believes this measure does not adequately account for loads on the subtransmission system, but the costs of the subtransmission system are included in marginal transmission capacity costs. DRA measures loads on the distribution substations, and recommends the following allocation of marginal transmission and distribution capacity costs:

	Coincident	Non-Coincident
Transmission	0.8750	0.1250
Distribution	0.3543	0.6457

PG&E now appears to concur with DRA's recommendation. TURN concurs with DRA's recommendation for reflecting the diversity of the residential class.

b. ACWA's Proposals

ACWA argues that the allocation of primary distribution capacity costs should be based on diversified demands, rather than a weighted combination of coincident and noncoincident costs, as recommended by PG&E and DRA. Although PG&E and DRA's approach reflects the diversity of demand for the residential and small light and power classes, this method is incapable of accounting for the diversity of the agricultural class. ACWA cites testimony that farmers have an inability, because of water delivery limitations and the demands of other aspects of agricultural work, to irrigate all fields at once. Therefore, no more than half of agricultural water pumps will operate simultaneously, according to ACWA.

ACWA also relies on testimony about average maximum and coincident demand at PG&E's substations to develop its recommendation that marginal primary distribution system costs should be allocated 83.2% to coincident demand and 16.8% to noncoincident demand to recognize diversity.

In a related recommendation, ACWA proposes use of a diversity factor of 0.5 to adjust the noncoincident demands for the agricultural class. This diversity factor reflects a typical agricultural customer's practice of irrigating only half of its fields at one time.

CFBF supports ACWA's recommendations. Because normal farming practices prevent simultaneous irrigation of all fields, no more than 50-75% of farming acreage will be irrigated at a time. Thus, PG&E's approach of merely summing up all installed demand on farms and ranches in its service area will overstate actual demand by at least 25%. CFBF believes that ACWA's recommended allocation of marginal primary distribution capacity costs more accurately reflects the diversity of the agricultural class.

DRA rejects ACWA's recommendations because ACWA has failed to present convincing evidence to support its position and has neglected to recalculate the marginal primary distribution costs that result from its approach.

PG&E opposes ACWA's approach on several grounds. First, ACWA has made two technical errors in developing its approach. More important, the basis of ACWA's recommendations--that agriculture's diversity is not adequately reflected in the allocations--is a misunderstanding. Agricultural transformers, like those serving other classes except for the residential and small light and power classes, serve no more than two accounts. Although a particular agricultural customer may have several accounts, no more than two accounts will be served by a given final line transformer. The maximum demand recorded at that transformer will reflect the actual demand drawn by the pumps on those accounts, regardless of whether other pumps on other accounts are operating at the same time. Thus, PG&E argues, the agricultural class' noncoincident demand is the sum of the maximum demands of all the meters, not all the pumps. PG&E's calculation of noncoincident demand for the agricultural class already reflects the diversity of multiple pumps served by the same account and measured by the same revenue and load research meters, and no additional adjustment is warranted.

c. Discussion

PG&E's final argument against ACWA's suggestions is a strong one. PG&E has consistently maintained that its final line transformers serve no more than two accounts, except for residential and small light and power customers. Once it is understood that a single agricultural customer can have multiple accounts, it becomes clear that the diversity of the accounts is accurately reflected by measurements of maximum demand at the final line transformer. With only one or two accounts served by a single final line transformer, the accounts' maximum, noncoincident demand will nearly always be identical to the demand at the final line transformer. Even if more than one pump is served by a single account, the load recorded at the final line transformer level will accurately reflect the diversified demand of the equipment.

As PG&E states, "The agricultural class' noncoincident demand is...the sum of the maximum demands on all the meters, not the sum of the demand of all the pumps. Thus PG&E's agricultural class noncoincident demand already reflects the diversity of multiple pumps attached to the same meter, so that no additional adjustment is warranted" (Reply Brief, p. 178).

We will not adopt the approaches suggested by ACWA. We will adopt DRA's recommendations for allocating marginal transmission and distribution capacity costs.

5. Adjustment of Generation Capacity Costs to Account for Reserve Margin Requirements

DRA argues that marginal generation capacity costs should be increased by the percentage of the target reserve margin. Because no generation unit is available all the time, an increase of one kW in demand requires a larger increase in generation capacity to meet that demand, according to DRA. If the reserve margin is 20%, for example, DRA states that the required increase in generation capacity needed to meet an additional kW of demand is 1.2 kW. Thus, in this example, generation capacity costs should be increased by 20% to reflect the full cost of meeting an extra kW of demand.

ACWA supports DRA's position.

PG&E agrees with DRA that an adjustment is appropriate when the ERI is at 1.0, indicating a need for additional capacity to meet the target reserve margin. When the ERI is less than 1.0, however, PG&E believes that no such adjustment is appropriate. When the system has excess reserves, an added kW of demand does not require an increment to the reserve margin, since the existing resources are adequate to maintain a reserve margin above the target. Addition of a kW of demand may reduce the system's reliability slightly, but no adjustment to marginal costs is appropriate.

We are not persuaded that any adjustment for the target reserve margin should be made to marginal generation capacity costs.

First, DRA's argument too glibly mixes the theoretical (the combustion turbine proxy used as a basis for marginal generation capacity costs) with the real (the target reserve margin, derived from the actual or forecasted loads and resources of the system). This blending of the theoretical and the actual raises questions that undermine DRA's proposal.

DRA's argument seems to turn resource planning on its head. If new generation capacity is needed, the amount of added capacity is not determined solely by the reserve margin. Rather, prospective new resources are considered from several perspectives, including overall cost and how well they match the system's needs for energy and capacity. The resource eventually chosen may in turn have an effect on the reserve margin: a new generating plant may be more reliable than the existing mix of resources and may permit a decrease in the target reserve margin. The extreme illustration of this notion occurs if the added capacity is a power purchase for which the selling utility provides all of the necessary reserves to back the sale.

This mixing of the theoretical and actual also seems to have a great potential for overestimating and overvaluing marginal generation capacity costs, at least under present circumstances. As we discussed in connection with the issue of modifying generation capacity costs by the ERI, the combustion turbine proxy may not always reflect the utility's actual options for adding capacity. If use of the proxy already overstates marginal costs, then increasing those costs by the target reserve margin amplifies the distortion.

We also find some validity to PG&E's point that when the utility's reserve margin is well above its target reserve margin, an increase in demand does not require any addition to reserves. This comment points out another aspect of the problems of combining a proxy with actual reserve margins.

PG&E's comment also exposes DRA's implicit assumption that the system is balanced between demand and resources (including the reserve margin) when the change in demand occurs. For example, if we assume that the utility's system has resources of 100 MW over its target reserve margin, then an increase in demand of one kW has no effect on the system's capacity costs. Similarly, if the system needs 100 MW to meet its target reserve margin, an increase of one kW of demand still leaves the system with a substantial need for additional capacity, with a marginal cost of additional capacity that is unaffected by the small change in demand. Only if the system is in equilibrium between supply and demand would DRA's precise adjustment come close to reflecting the actual circumstances of the system.

These comments demonstrate that we have many unanswered questions about DRA's proposal. These questions have not been addressed in this case, and we therefore decline to adopt the adjustment DRA proposes.

B. <u>Caps and Floors</u>

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. This same percentage change is then applied to the marginal cost revenues for each individual customer class in order to derive the EPMC revenue allocation for that class. Although we have moved toward an allocation based on EPMC, several classes still remain substantially above or below their EPMC levels, and we have moderated our progress toward EPMC to avoid disruptive rate effects.

In this case, all parties endorse the EPMC approach, with limits (caps and floors) to moderate the rate effects on particular classes. The parties differ, however, on the levels of appropriate caps and floors, and our discussion will accordingly focus on the parties' reasons for advocating their favored levels of caps and floors.

1. The Parties' Positions

a. PG&E

PG&E believes the level of the caps or floors should relate to the level of the revenue increase for the overall system. When increases are small, the Commission has an opportunity to bring the classes closer to EPMC without disproportionate rate effects on any single class. When increases are large, the interest of rate stability overwhelms the desire to reach full EPMC, and slower progress toward EPMC is justified.

PG&E therefore relates its recommendations for caps and floors to the overall system average percentage change (SAPC) in revenue requirement. When the overall increase is 5% or less, the change for a particular class is bounded by the SAPC plus or minus 5%. When the system increase is more than 5%, changes are limited to SAPC plus or minus 2.5%. The Commission would have the flexibility to deviate from strict application of these limits to adjust for particular circumstances.

PG&E argues that its proposal treats all customer classes fairly and equitably, unlike other parties' proposals with asymmetrical caps or unequal treatment of particular classes. PG&E also contends that its approach will promote rate stability by moderating the effect of movement toward EPMC when revenue increases are comparatively high.

CFBF supports PG&E's scheme of caps and floors, especially as applied to the agricultural class.

Other parties criticize PG&E's recommendations.

DRA states that PG&E's proposals do not meet three criteria that DRA believes are important for revenue allocation. (These criteria are discussed in more detail in the section on DRA's proposals.) Certain inconsistencies occur if the SAPC is around 5%: when SAPC is 4.5% the cap is 9.5%, but the cap is only 8.0% when SAPC is 5.5%. The signal to customers about what to expect in the future is unclear, because some classes receive increases even if an EPMC allocation would result in a decrease. Guidance for future proceedings is also missing, since PG&E has no proposal for caps or floors when the system's revenue requirement decreases by more than 5%.

TURN agrees with DRA that PG&E's system of caps is inconsistent and difficult to implement and will sometimes result in counterintuitive rate changes.

CLECA argues that PG&E's proposed pace for achieving an EMPC-based allocation is much too slow. Nearly 18 iterations of PG&E's proposed revenue allocation process would be needed to bring the agricultural class to full EPMC. PG&E's proposal does not bring a class up to the cap even when the class' EPMC allocation exceeds the cap, an illogical result, in CLECA's opinion. CLECA also points out that slowing progress toward EPMC when overall revenue increases are large exacerbates the distortions of existing class relationships.

Industrial Users also conclude that PG&E's proposal moves too slowly toward a revenue allocation based on EPMC. Even with no rate increase, PG&E's approach would leave the agricultural class nearly 25% short of its EPMC-based revenue responsibility, at the expense of other classes. In addition, PG&E's emphasis on symmetry ignores the many past asymmetrical allocations that led to the current distortions among the customer classes.

Cal-SLA criticizes PG&E's proposal for the slow pace of its progress toward an allocation based on EPMC. For the streetlighting class, PG&E's proposals would require 20 years before the allocation to the streetlighting class reached its EPMC level. Cal-SLA finds this pace unacceptable.

b. DRA

DRA's proposal for caps and floors depends on whether the system's revenue requirement increases or decreases.

When the system's revenue requirement rises, increases for a particular customer class would be capped at 5% above the system's average increase. DRA's proposed floor would be no decrease, and no class that would receive a decrease under an EPMC allocation would receive an increase when the caps are applied.

When the system's revenue requirement decreases, the cap for an individual class would be no increase, and the floor would be 5% below the system's average decrease.

DRA believes its proposal for caps and floors reflects the Commission's decisions in this area for the past three years. DRA deviates from the Commission's past rulings only in applying a uniform cap to all classes; DRA submits that the lower cap formerly applied to the agricultural class is no longer needed, since the transition to new agricultural tariffs has been completed.

DRA also argues that its proposals meet three criteria it believes are important in revenue allocation. First, the structure of caps and floors for revenue allocation should be free from inconsistencies and should apply in an understandable and unambiguous manner over a range of revenue changes. Second, the structure should give customers clear signals about what to expect in future proceedings. Third, the structure should provide guidance for future revenue allocations.

DRA believes its system of no increases when decreases would be dictated by an EPMC allocation helps avoid problems of public perception, which could occur when some classes get increases and others decreases.

DRA makes an exception to its proposals for the streetlighting class. Because of the small revenue effect, DRA is willing to allocate revenue to the streetlighting class on a full EPMC basis, which will result in a decrease in rates.

PG&E opposes DRA's no-increase or no-decrease approach to setting floors and caps because PG&E believes this approach will lead to asymmetrical and inequitable revenue changes for different classes. PG&E also points out that DRA's approach makes little or no progress toward EPMC when revenue requirement changes are small, even though such cases are ideal times to make substantial progress toward the EPMC goal.

TURN opposes DRA's recommendations. TURN believes DRA's system of no increases and no decreases is rigid and will result in asymmetric revenue changes to different classes.

CLECA thinks DRA's proposed pace toward EPMC is too slow. DRA's proposal has the illogical result of making no progress toward EPMC when the overall revenue requirement change is small, a time when the Commission has normally been able to make significant movement toward EPMC without undesirable rate effects. DRA's concern about public perception does not outweigh the need to improve efficiency and avoid subsidies, and the Commission could counter this perception by making a clear statement of its intent to achieve a full EPMC-based allocation within a reasonable period, CLECA contends.

Industrial Users think DRA's approach is better than PG&E's, but they note that anomalous results occur when revenue changes are relatively small. Industrial Users also find DRA's approach, like PG&E's, to be mechanistic and needlessly inflexible. Like CMA, Industrial Users think DRA weighs anticipated public perception too heavily in arriving at its recommendation.

c. TURN

TURN recommends that the revenues allocated to individual customer classes should be bounded by SAPC plus or minus 5%. TURN makes an exception for the streetlighting class by proposing the SAPC minus 10% should serve as the floor for any decreases to that class. Under TURN's proposal, any revenue shortfall resulting from application of the caps would be spread on an EPMC basis to all classes not receiving a capped increase, including those initially receiving a capped decrease.

TURN contends that its proposal is clear, easy to apply, equitable to all classes, and consistent with the Commission's past practice for PG&E. A larger decrease to the streetlighting class is acceptable to TURN because of the class' extreme deviation from EPMC, its small size, and its public character.

d. CMA

CMA lists two primary question relating to caps and floors: how far should the Commission go to avoid rate shock and how should the costs of avoiding rate shock be borne by other customer classes? For customers now paying rates higher than those resulting from an EPMC allocation, CMA believes the central issue is how much longer they must subsidize classes with revenues at less than full EPMC.

In considering these questions, the Commission should commit itself to a schedule for reaching a revenue allocation based on full EPMC, CMA believes. Efficient planning for both the subsidized and subsidizing classes requires a knowledge of how much longer the subsidies will continue. CMA urges the Commission to reach a revenue allocation based on full EPMC by the next general rate case for PG&E. To do that requires a focus on eliminating the subsidy to the agricultural class, which currently receives the largest subsidy. CMA proposes removing half of the existing subsidy to the agricultural class in this rate case, half of the remaining balance next year, and the remaining amount in the following year.

As long as the subsidies continue, CMA believes that the revenue shortfall should be recovered from all other classes, with no exceptions.

CMA's guidelines for applying caps in this rate case include the proposal to increase the agricultural class' allocation by one-half the difference between revenues at present rates and revenues at full EPMC rates. For other classes, the increase should be limited by SAPC plus 5% when there is an overall increase in revenue requirements and SAPC minus 5% if there is an overall decrease. No class that would receive a decrease under an EPMC allocation would receive an increase until all unsubsidized classes pay the same percentage above full EPMC.

PG&E opposes CMA's separate treatment of the agricultural class. The 25% increase that the agricultural class would suffer under CMA's proposal is too severe, in PG&E's opinion, and the desire to attain a full EPMC allocation quickly must be tempered by a consideration of the increases in revenue responsibility for individual classes.

TURN criticizes CMA's proposals because they increase agricultural rates at too fast a pace and include inequitable caps of no increase for classes currently above their EPMC allocations.

e. <u>CLECA</u>

CLECA echoes CMA in urging the Commission to make steady and rapid progress toward an allocation based on EPMC. Like CMA, CLECA believes this goal can be achieved by PG&E's next general rate case.

CLECA's proposal for class revenue changes during the period when subsidies still exist is a range bounded by SAPC plus or minus 5%. Within the range of likely increases resulting from this case, caps would be needed only for the agricultural and small light and power classes. The revenue shortfall would be spread on an EPMC basis to all uncapped classes, so that all uncapped classes would equally subsidize the capped classes.

To assure achievement of an EPMC allocation in a reasonable time, CLECA urges the Commission to follow its proposal on revenue allocation in every proceeding with a significant revenue impact, including general rate cases, ECAC proceedings, and the attrition rate adjustment.

TURN finds CLECA's approach to be similar to the one it recommends, but notes that CLECA allocates revenue shortfalls only to uncapped classes, rather than to all classes, as TURN proposes. TURN thinks its method is superior because it produces results that are independent of the size of the rate change.

f. FEA

FEA agrees with CMA and CLECA that the Commission should have a structured plan to achieve an EPMC revenue allocation. FEA's recommendations are geared to arriving at that goal in three steps. With each opportunity for a revenue realignment, the Commission should take another step towards its goal, FEA urges.

FEA believes that general guidelines on revenue allocation are preferable to the mechanistic formulas proposed by DRA and PG&E. FEA's proposed guidelines for revenue allocation depend on the level of overall revenue increase.

For a $65 million increase, FEA moves the railway, agricultural, and streetlighting classes one-third of the way toward an EPMC allocation. Other classes with increases receive a full EPMC allocation, and classes receiving decreases get prorated decreases to reflect the difference between full EPMC and the amount needed to meet the revenue requirement.

For a $285 million increase, the agricultural class moves one-third of the way to its EPMC allocation, and the streetlighting class moves one-half of the way. The remaining revenue requirement is allocated to other classes on a full EPMC basis.

If the overall increase is $585 million, increases to the small light and power, large light and power, and agricultural classes are limited to 15%. The streetlighting class again moves one-half of the way to its EPMC allocation, and the remaining increase is allocated among the other classes on a full EPMC basis.

PG&E criticizes FEA's different treatment of different classes as being inconsistent, unnecessarily complicated, and inequitable.

TURN finds that FEA's method produces inconsistent results at different levels of revenue change and results in some extreme changes for some classes when increases of revenue requirements are high.

g. Industrial Users

Industrial Users recognize that formulating appropriate caps and floors on revenue allocation requires balancing the need to assure that no customer class receives an inordinately large increase against the importance of moving quickly toward a revenue allocation based on EPMC. To achieve the proper balance between these competing concerns, Industrial Users' recommend limiting increases to 10% or 1.5 times SAPC, whichever is larger. Under Industrial Users' proposal, no floor would be set unless the overall increase in revenue requirement exceeded 10%. When revenue requirement increases reached that level, a floor of no decrease would apply.

Industrial Users believe this approach is superior to a fixed percentage band, such as PG&E and DRA recommend. Unlike PG&E's and DRA's recommendations, Industrial Users' proposal does not limit the progress toward full EPMC without considering whether a limitation is necessary in the context of the overall level of revenue increase or decrease. Industrial Users argue that their recommended approach allows reasonable progress toward EPMC without disruptive rate increases to any class. For a revenue increase of $285 million, for example, no class receives an increase of more than 5.5% above SAPC.

PG&E argues that the approach to caps advocated by Industrial Users results in greater rate increases when the overall system's increase was comparatively large. The effect on some class' rates is exacerbated by Industrial Users' proposal, leading to unacceptable rate instability, in PG&E's view.

TURN believes Industrial Users' recommended caps could produce excessive rate increases for some classes.

h. ACWA

ACWA is alone in raising questions about the desirability of proceeding to a revenue allocation based on EPMC. ACWA cites economic treatises to support its point that prices above marginal costs result in efficiency losses. Since the present function of the EPMC approach is to increase revenue responsibility from marginal cost levels to reach the revenue requirement, the resulting rates will be above marginal cost and will create some inefficiency. ACWA urges the Commission to proceed with caution in reaching its goal of a revenue allocation based on full EPMC.

More specifically, ACWA advocates a revenue allocation that would apply the SAPC to revenue increases or decreases of 5% or less; larger increases or decreases would be allocated on the basis of EPMC capped at 5% above SAPC. ACWA also suggests that if PG&E's actual costs of fuel continue to exceed its marginal energy costs, then general rate case revenues should be allocated by marginal customer and demand-related costs, but ECAC and Annual Energy Rate (AER) revenues should be allocated by marginal energy costs.

Despite its reservations about the EPMC approach, ACWA recommends that increases to individual classes should be capped by SAPC plus 5% if the Commission adopts a capped EPMC allocation.

TURN finds ACWA's approach to be inconsistent with the Commission's previous decisions.

i. Cal-SLA

Cal-SLA strongly urges the Commission to move the streetlighting class to its EPMC allocation in this proceeding.

Cal-SLA points out that the streetlighting class is the farthest from EPMC of any class; it currently contributes revenues that are 32.23% above its EPMC allocation. Although the move to a full EPMC allocation would seem dramatic, the effect on other customers would be minuscule, because streetlighting is the smallest class. A revenue allocation based on full EPMC would shift less than $10 million in revenues to other classes and would result in an average increase for other customers of only 0.16%. Furthermore, the services supplied by streetlighting benefit the members of other classes directly by providing safety to drivers, pedestrians, and buildings and dwellings adjacent to roads. No other party has supplied a reason for further delaying the move of the streetlighting class to its EPMC allocation, according to Cal-SLA.

PG&E opposes special treatment for the streetlighting class. PG&E argues that the Commission should not begin a precedent of "ignoring a uniform, equitable allocation scheme for the benefit of a single class," a process that PG&E believes "can only result in a series of me-too requests for 'exceptions' in the future."

DRA states that it is not opposed to exempting the streetlighting class from its proposed caps, because of the small revenue effects and the disproportionate revenue responsibility that streetlighting bears under current allocation structures.

TURN finds Cal-SLA's proposal to put only the streetlighting class at its full EPMC allocation to be parochial.

2. <u>Discussion</u>

After reviewing and considering the parties' positions on the issue of caps and floors, we have concluded that an approach similar to the one suggested by CLECA should be followed in this case. We find that this approach provides the best balance between moving toward our goals of achieving an allocation based on full EPMC and avoiding large rate increases for a particular customer class.

Within the range of revenue increases that have been discussed in this case, application of a cap of 5% plus SAPC requires caps for only the agricultural and small light and power classes, and the 5% limit keeps these increases within a range that we find reasonable in light of all the circumstances. Other proposals either move too slowly toward EPMC or result in unbearably large increases to some classes.

One exception we will make to CLECA's proposal has to do with the treatment of the streetlighting class. CLECA imposed its floor of 5% below SAPC on this class. Other parties advocated the immediate reduction of this class' revenue responsibility to EPMC levels. We believe that we can and should make substantial progress toward reducing the burden on this class. For this case, therefore, we will move one-third of the way toward the EPMC allocation for the streetlighting class. We will also state our intent to continue this reduction in the next three years, so that the streetlighting class will receive its EPMC allocation in the next general rate case. Whether or not we are able to carry out this intent will depend on the circumstances that we will face in the next three years. We agree with many of the parties that the shift of revenues and the effect on other customers resulting from this action will be fairly minor.

The revenue shortfall due to the application of caps and the movement of the streetlighting class toward EPMC should be recovered, as CLECA suggests, from all uncapped classes on an EPMC basis.

In addition, we will set the cap for the agricultural class at 2% above SAPC. The agricultural class is still in the midst of a widespread conversion to TOU schedules, and we expect the new schedules to alter the class' usage patterns and eventually to lower the class' revenue responsibility. A 5% cap would lead to harsh rate impacts that may not prove to be justified and that would, in effect, punish agricultural customers for more efficient behavior. To avoid this result, we will take several steps, starting with the 2% cap, to control the rate impacts on agricultural customers.

We agree with many parties that a revenue allocation based on these principles should take place whenever there is a substantial change in revenue requirement. The most likely and logical forum for these allocations is the ECAC case. The marginal capacity and customer costs we adopt in this decision should be used in performing this allocation.

In these subsequent allocations, we will use caps and floors of SAPC plus or minus 5% as a guideline in developing a revenue allocation, except for the streetlighting class. However, we caution parties against overrelying on this figure or this formula, and we reserve the right to fit the revenue allocation to the particular circumstances that we face at the time.

C. Revenues from Special Contracts

Our decisions in I.86-10-001 have permitted utilities to enter into special contracts with customers who have the ability to bypass the utility's system. The rates prescribed in these contracts are negotiated between the utility and the customer, but the rates must recover at least the costs the utility incurs in serving the customer. (D.88-03-008, mimeo. pp. 6-7.) Presumably, most of these contracts will provide for service at a price that is less than the tariff rate that would normally apply to the customer.

An issue arose in this case about how to account for the revenues from these special contracts.

1. The Parties' Positions

a. PG&E

PG&E believes that the sales, marginal costs, and revenues from special contracts should be excluded from the revenue allocation process. The revenues from these contracts are calculated at the rates developed in the contracts, and their total revenue is used to reduce the total revenue requirement allocated to other customers. In this way, the Commission's conclusion that "the risk of loss from bypass and special contracts remains on ratepayers" (D.89-05-067, mimeo. p. 10) is carried out through the revenue allocation process.

b. CMA

CMA appears to agrees with PG&E, and its witness developed his recommended revenue allocation by excluding the revenues from special contracts.

c. DRA

Although it has some reservations about its approach, DRA calculates the revenues from special contracts at tariff rates, rather than at the rates called for in the contracts. DRA uses the resulting revenues in its calculation of revenues at present rates and in its revenue allocation. DRA believes this treatment is consistent with the Commission's previous decisions. Even if some of PG&E's proposals are adopted, DRA thinks special contracts should be included in the EMPC-based revenue allocation, either as part of Schedule E-20 or as a separate customer class. DRA argues that it is logical to keep the sales from special contracts and other jurisdictional retail sales together. It also makes sense to group sales from special contracts with other energy sales and to distinguish them from facilities charges and other unallocated revenues. The only necessary separate treatment of special contracts is to develop the revenue allocation to these customers independently, rather than through an allocation based on EPMC.

d. FEA

FEA believes that special contracts customers should be imputed the revenue that would result if they were charged at tariff rates and should be assigned marginal costs like any other large customer. Revenue responsibility should be assigned on an EPMC basis, and any revenue shortfall should be handled as part of the consideration of ERAM issues, presumably in the ECAC proceeding.

e. CLECA

CLECA initially supported DRA's position, but it now believes that PG&E's proposal to exclude special contracts from revenue allocation makes sense in theory. In practice, however, including contract sales at contract prices assumes that the prices are reasonable, and the Commission has not yet ruled on the reasonableness of many of these contracts. CLECA therefore proposes varying the treatment of revenues from these contracts according to status of the Commission's review of their reasonableness. If the Commission has found a contract reasonable, the contract's revenue is treated as unallocated revenue and valued at the prices called for in the contract. If a contract has not yet been reviewed by the Commission, then revenues are based on appropriate tariff rates, but the revenues are excluded from Schedule E-20 for revenue allocation purposes. If a contract has been found unreasonable, then its sales are presumed to be at tariff rates and are included in the allocation.

CLECA believes that its proposal overcomes the problem of prejudging the Commission's determinations about specific contracts.

f. TURN

TURN recommends a treatment similar to DRA's proposal. TURN, however, includes special contracts in calculating the revenue responsibility for Schedule E-20. Under TURN's proposal, revenues are developed for all customers who qualify for service under Schedule E-20, including special contracts customers, and any revenue shortfall is recovered through the Electric Revenue Adjustment Mechanism (ERAM).

2. Discussion

The central problem here is how to accommodate the existence of special contracts, with rates at levels less than those prescribed by tariffs, without distorting the revenue allocation. In the absence of special contracts, all retail sales are accounted for in the allocation process at tariff rates. With the rise of special contracts, which primarily attract customers normally served under Schedule E-20, the revenues from some customers will be lower.

Although it appears that some parties have read too much into D.89-05-067, it is clear that we have decided that the shortfall in revenues that results from special contracts will be borne by other customers and not by the utilities. Our attempts at shifting more of the risk of reduced revenues to the utilities met many substantial obstacles, and we were forced to continue the existing assignment of the responsibility of reduced revenues to ratepayers.

Allocating lower revenues resulting from special contracts over a relatively smaller sales base creates the potential for distorting the allocation among the classes. The ideal allocation would maintain the relationships among the customer classes that would exist if the need for special contracts had never arisen. The parties have proposed two ways that seem to accomplish this goal.

DRA and FEA seem to propose that, for purposes of revenue allocation, special contracts should be imputed the revenues that would result if the same sales had been made at the appropriate tariff rate. The resulting shortfall in revenues (the difference between tariff and contract rates for the sales associated with special contracts) is then recovered from all customers through the ERAM account. This approach has the virtue of keeping all energy-related revenues together in the allocation and makes calculation of the jurisdictional allocation easier. The drawback to this proposal, as PG&E points out, is that it creates an undercollection in the ERAM account. We have followed this approach in recent allocations while we awaited the conclusion of I.86-10-001.

A second approach also appears to maintain the relationships among the customer classes in the revenue allocation. PG&E proposes removing all sales and revenues associated with special contracts from the allocation process. Removing both revenues and sales leaves the relationships among the other classes unaltered. However, the other classes make up the revenue shortfall by receiving slightly higher responsibility for the system's fixed costs (after receiving credit for the contribution to margin made by special contracts customers). Thus, rather than making up for the lost revenue in higher ERAM rates, other customers will see slightly higher rates due to the revenue allocation.

This approach could be seen as creating a distortion by lowering the sales and revenues associated with Schedule E-20. The sales and the credit for recovery of marginal costs (special contracts must at a minimum recover the cost of producing the power sold under the contract) would be removed from Schedule E-20. However, we have limited special contracts to customers who would leave the system except for the option of a lower rate (or to those who will increase short-term consumption in response to a lower rate). In the absence of special contracts, these sales would not occur, and the customer would leave the system entirely. Thus, the remaining members of Schedule E-20 are no worse off if the sales and revenues associated with the special contracts are removed from the allocation than they would be if the special contracts customers left the system.

We will adopt the approach suggested by PG&E and CMA for use in this case. As we have suggested, both this approach and the one proposed by DRA and FEA (and followed in recent years) appear to allow for a revenue allocation that is not distorted by the reduced revenues from special contracts. We are concerned, however, about the built-in ERAM undercollection that is part of DRA and FEA's approach. This undercollection did not worry us when reliance on ERAM to recover the revenue shortfall from special contracts was viewed as an interim measure. But a persistent and automatic undercollection of revenues in ERAM seems to us to be a bad policy for anything but the short term. PG&E and CMA's approach avoids this problem, and we will adopt this treatment of special contracts in the revenue allocation.

D. <u>Allocated and Nonallocated Revenues</u>

DRA notes that in PG&E's last general rate case we distinguished between revenues from tariff rates that recover the types of costs that are included in the revenue allocation (allocated revenues) and revenues that reflect other types of costs or savings (nonallocated revenues). Nonallocated revenues include streetlight facilities charges, meter charges for optional time-of-use (TOU) service, meter charges for optional nonfirm service, submeter discounts, and other operating revenues.

DRA advocates continuation of the distinction between allocated and nonallocated revenues. DRA suggests, however, some refinements. First, load management credits and rate discounts for nonfirm service should be included in allocated revenues, and the corresponding coincident capacity value should be credited to customer classes for participation in all load management programs. Second, power factor revenues should be treated like facilities charges and included in nonallocated revenues. Third, certain facilities charge revenues--the facilities charge for the Bay Area Rapid Transit District (BART) and the University of California at Berkeley discount, for example,--should be excluded from allocated revenues.

DRA's method for allocating nonfirm discounts and load management credits uses actual marginal cost revenue responsibility and revenues at present rates. This method strives for maximum consistency in revenue allocation for load changes that impose the same cost on the utility. Under this approach, customers in each class pay for the discounts extended to members of that class, and the benefits of reduced costs of service also remain within the class.

CLECA and CMA support DRA's approach.

ACWA agrees that nonfirm discounts and load management credits should be collected within the class that would normally provide firm service to these customers.

PG&E treats customers electing nonfirm service and load management options as firm customers and credits their capacity savings against their final revenues. Under this approach all customers pay a share of the nonfirm and load management discounts.

In the update hearings, PG&E, DRA, and CLECA sponsored a joint exhibit (Exhibit 88), which included a resolution of the issue of revenue allocation to nonfirm customers.

The joint exhibit addresses many issues other than revenue allocation. Many of the more significant provisions of the joint exhibit concern rates for nonfirm customers. We address all of the provisions of the joint exhibit, including its proposal for revenue allocation, in the rate design portion of this decision.

Our resolution of the treatment of discounts for nonfirm customers affects our adopted approach to allocated and nonallocated revenues. Capacity savings from nonfirm service and load management programs should be credited against these customers' rates. The revenue allocation then spreads the costs of the associated discounts to all customers.

For other elements of nonallocated revenues, we will adopt DRA's approach. The recommended treatment of facilities charges is consistent with our overall attempt to unbundle rates for the streetlighting class.

E. Revenue Allocation to the Agricultural Class

1. Treatment of Schedule AG-5 Revenues

ACWA proposes to exclude revenues from Schedule AG-5 from the revenue allocation. The primary basis for this exclusion is the similarity between customers on Schedule AG-5 and those receiving service under negotiated special contracts. ACWA contends that both groups of customers have access to alternative energy sources, and rates for both groups are designed to retain customers on the system, provided marginal costs are recovered. The level of the rates offered these customers are set to compete with the costs of the customers' alternate energy sources.

Because several parties urge us to exclude the revenues from special contracts from the revenue allocation, ACWA believes that consistency and equity demand equal treatment for revenues from Schedule AG-5.

In a similar vein, CFBF argues that any agricultural customer with consumption of 2,000 kWh per kW is a candidate for bypass and should be removed from the calculation of the agricultural class' marginal cost revenues and revenue allocation. This treatment would put such customers on an equal footing with commercial and industrial customers who are likely to bypass the system.

DRA opposes ACWA's proposal. DRA believes its approach to intraclass revenue allocation and rate design results in a rate for Schedule AG-5 that is competitive with diesel-fueled pumps. The rate for Schedule AG-5 is already close to marginal cost and should not be lowered. The Commission has stated that rates for negotiated special contracts should recover at least marginal costs, and the same principle should apply to Schedule AG-5. Any bypass that occurs because the customer's cost is less than the utility's marginal cost is economic bypass, and the Commission has not attempted to deter economic bypass for any customer group. The rationale for special contracts disappears when rates are close to the marginal cost of the utility's service. The fact that AG-5 rates are close to marginal cost distinguishes this schedule from special contracts, in DRA's opinion.

We agree with DRA that revenues from Schedule AG-5 should be included in the revenue allocation like revenues from any other tariff schedule. We see significant differences between negotiated special contracts and Schedule AG-5. Special contracts allow certain customers to negotiate a rate below the otherwise applicable tariff rate, but above the utility's cost of serving the customer. The rate for each contract depends on the circumstances of the individual customer, and the utility should try to recover as much revenue as possible from a particular customer. Schedule AG-5 applies to a large group of customers, with many varying circumstances. Trying to peg a tariff rate to some idealized customer's situation would undoubtedly lead to an unnecessary loss of revenue, because the tariff rate would apply to many customers who are willing to pay a higher rate for service.

In addition, the rate for Schedule AG-5 is close to marginal cost, and, as DRA pointed out, we have not attempted to deter economic bypass.

Finally, we believe the rate resulting from this decision is low enough to compete with the alternative of diesel fuel.

2. <u>Balancing Account</u>

ACWA suggested that agricultural revenues be removed from the ERAM account and recorded in a separate agricultural balancing account. The agricultural class has a greater fluctuation in sales than other classes, and billing determinants for the class vary widely from the forecasts, according to ACWA. PG&E's load and market research data are accordingly worse than for other classes. In addition, the agricultural class has many more firm service options than other classes. These characteristics argue for a separate ERAM balancing account, in ACWA's opinion.

PG&E opposes ACWA's suggestion. PG&E argues that the foundations for ACWA's proposal have not been supported by the record, and even if they were, ACWA has not shown why its proposal is a rational response to these conditions. ACWA's recommendation is not based on costs and would distort and complicate the ERAM process. In addition, creation of a separate ERAM account for agriculture would significantly complicate the sales forecast portions of subsequent general rate cases and ECAC proceedings. PG&E finds ACWA's proposal to be an attempt to receive favorable treatment in the allocation process.

DRA also opposes ACWA's suggestion. DRA points out that the fluctuation in agricultural sales, when combined with a separate balancing account, could hurt the agricultural class if forecasted sales are higher than actual sales, resulting in an undercollection that would be recovered the following year. The uncertainty about agricultural sales that ACWA has cited in support of its proposal underscores DRA's concern. This undercollection could result, for example, if more agricultural customers than forecasted convert to TOU rates. Agricultural customers should not be punished, in DRA's opinion, for making wise choices among rate options.

ACWA has not justified the need for a separate ERAM account for the agricultural class. DRA has shown that this proposal could have detrimental effects on the agricultural class, and we will not adopt ACWA's recommendation.

3. Treatment of Water Pumpers

ACWA asks the Commission to investigate whether all water pumpers should be classified as agricultural customers. ACWA believes that water supply customers now served on general service schedules have more characteristics in common with agricultural water pumpers than with other commercial customers.

DRA opposes ACWA's suggestion. DRA notes that ACWA presented no evidence in support of its request, and DRA resists the notion that classes should be redefined according to allegedly similar load patterns.

PG&E also opposes ACWA's request. The Commission has already considered this issue in PG&E's last general rate case. The Commission recently elaborated on its conclusions in that case by moving water pumpers who use 70% of their energy for agricultural purposes to agricultural schedules (D.88-12-031, pp. 21-22). PG&E argues further that switching municipal water pumpers to agricultural schedules will not effectively increase the rate options for those customers.

We are not persuaded that an investigation of ACWA's suggestion is warranted at this time. AWCA has failed to show that any substantial benefits are likely to result from this investigation.

4. Reliability Adjustment

ACWA argues that rural customers face twice as many service interruptions as urban customers, and those interruptions last three times as long as in urban areas. ACWA believes this lower quality of service should be reflected in the revenue allocation. The recommended adjustment is a reduction for the agricultural class of $1.59/kW of coincident peak demand.

PG&E opposes this adjustment. An adjustment to coincident peak demand primarily affects marginal generation capacity costs, but no connection exists between rural service interruptions and generation: generation reliability problems affect all customers equally, not just rural customers. Thus, it would make more sense to adjust the allocation of distribution-related costs, but ACWA has failed to develop a record to support that adjustment.

We agree with PG&E that the record does not support ACWA's recommendation. We urge PG&E, however, to take steps to improve the reliability of service to its rural customers.

IX. Intraclass Revenue Allocation

Once revenue is allocated to the customer classes, each class' revenue responsibility must be divided among the various tariff schedules making up the class. Intraclass revenue allocation and rate design overlap somewhat, and we address the bulk of these related issues in the section on rate design. Two issues are more narrowly concerned with intraclass revenue allocation.

A. Caps and Floors

Many parties propose the same caps and floors for both inter- and intraclass revenue allocation.

PG&E proposes a capped EPMC-based allocation similar to its recommendation for interclass allocation, with caps of 5% or 2.5%, depending on the level of class percentage change.

DRA recommends that the revenue allocation to schedules within a particular class should be bounded by a cap or floor of 5% above or below the class' average percentage change that results from the interclass allocation.

CLECA thinks the current two-step revenue allocation should eventually be eliminated, and revenue responsibility should be allocated directly to each schedule. For the intraclass allocation in this proceeding, CLECA supports caps and floors of 5% above or below the class average revenue change resulting from the interclass revenue allocation (Exhibit 283, pp. 4-5).

CMA states that the same goals of equity and economic efficiency that guide interclass revenue allocation should apply to intraclass revenue allocation and rate design. The goal of an intraclass allocation based on costs must be balanced against the need for rate stability.

CMA implements its policy recommendations in its suggested intraclass allocation for the large light and power class. Rates for the proposed Schedule E-19 and for Schedule E-20 were developed by setting caps and floors at 5% above or below the combined change in revenue responsibility for the large light and power class.

ACWA's primary position is that revenue allocation should be based on marginal costs, unadjusted for EPMC. If the Commission adopts an allocation based on EPMC rather than marginal costs, ACWA supports DRA's approach. ACWA recommends one exception to DRA's scheme. For the agricultural class, the need to set rates for Schedule AG-5 at levels that compete with diesel pumping means that rates for that schedule are lower than the intraclass EPMC-based allocation. If this revenue difference is made up within the class, other agricultural customers are unfairly penalized for sales made under Schedule AG-5. This argument supports ACWA's position that the revenue shortfall associated with Schedule AG-5 should be shared by all classes.

We will adopt DRA's basic approach to intraclass revenue allocation. DRA's recommendation is consistent with our adopted approach to interclass revenue allocation, and the recommended caps and floors are in line with the positions of several other parties.

Our concern about harsh and unwarranted effects on agricultural customers, however, leads us to adopt a different approach to the agricultural intraclass allocation. We will set the revenue responsibility for Schedule AG-5 equal to its marginal cost revenue responsibility, to aid in keeping this schedule competitive with alternate pumping fuels. The remaining class revenue allocation will be assigned to the other schedules on an SAPC basis.

B. <u>Allocation to Residential TOU Schedules</u>

The assignment of revenue responsibility to the schedules of the residential class is complicated because parties have proposed two new TOU schedules. PG&E proposed a new Schedule E-8, and DRA proposed a new Schedule E-9. The details of these schedules are described in the rate design section of this decision.

Although DRA and PG&E agree to a large extent on how to allocate revenue to the residential schedules, two major differences remain. First, PG&E did not include DRA's proposed Schedule E-9 in its allocation, because it opposes this schedule. This issue will be resolved when we decide the disposition of the proposed schedules in the section on rate design.

Second, the parties differ in their estimates of the usage characteristics and number of customers on the new TOU schedules.

PG&E's approach relies on a number of assumptions about the average usage by customers on the new schedules, the average rate for those schedules, and the number of customers who are likely to take service under the new optional schedules.

DRA argues that it refined a number of PG&E's assumptions and thus its results are more reliable than PG&E's.

TURN's allocation to residential schedules includes a proposal for a revenue-neutral allocation to the existing TOU option, Schedule E-7. As an alternative to this recommendation, TURN suggests capping the allocation to this schedule at 5% above the percentage change for the residential class.

DRA and PG&E oppose TURN's suggestions because TURN fails to recognize the differences in costs that different customer groups cause the system to incur. One of the primary functions of revenue allocation, these parties argue, is to reflect such cost differences. TURN's proposals ignore this goal.

We agree with PG&E and DRA that a cost-based allocation to the residential schedules is important and should be followed. We accordingly reject TURN's proposed allocation to Schedule E-7. On the remaining differences between PG&E and DRA, we note that DRA was able to get PG&E's witness to agree to a number of its refinements of PG&E's assumptions. We conclude that DRA's approach should be followed in developing the usage characteristics, number of customers, and resulting revenue allocation to the new TOU schedules. Subject to the modifications needed to accommodate the determinations of this decision, we conclude that DRA's approach to intraclass revenue allocation should be followed in this case.

X. Rate Design

As we noted in connection with revenue allocation, rate design for gas service is addressed in the ACAP. Although this section primarily concerns electric rate design, some issues affecting gas rates are also considered.

A. General Recommendations

Some of ACWA's recommendations relate to rate design for several customer classes.

Consistent with its position that rates should reflect marginal costs, rather than EPMC, ACWA recommends setting customer and demand charges at marginal cost. ACWA also suggests that customer charges should reflect the cost differences between underground and overhead service; classes benefitting from more expensive underground service should bear more of the costs in their customer charges. The balance of the revenue allocated to the class would be assigned to energy charges in proportion to marginal costs for each TOU period. Under EPMC, all rates will exceed marginal costs, and ACWA's suggestion ensures that only a few rate components will be above marginal costs. Not all classes have customer or demand charges, so using energy charges to recover unallocated revenue requirement will provide consistent economic signals to all classes. In addition, marginal energy cost will rise faster than revenue requirement, so that energy charges and marginal costs will converge.

ACWA also recommends increases to specific rate components. Customer charges for all classes should be based on the same proportion of marginal cost, and annual increases should be limited to 5% until charges equal marginal costs. Demand charges should move toward marginal costs at 5% per year. For rates differentiated by time and season, the on-peak charge should move toward marginal cost at 5% per year.

DRA opposes ACWA's recommendations because ACWA did not consider customers' price elasticities for the services that correspond to the various rate components. The rate design emerging from ACWA's recommendations would be distorted, DRA believes.

We have already considered and rejected ACWA's underlying premise, that prices should correspond to marginal cost rather than to an EPMC-based allocation. In light of our previous determination and DRA's point about price elasticities, we will not adopt ACWA's recommendations.

B. Residential Class

PG&E's basic residential service is provided under Schedule E-1. Energy is provided at a lower rate for usage up to the customer's baseline quantity, which varies with season and climate zone (Tier 1), and additional consumption is charged a higher rate (Tier 2). A minimum bill of $5 is applied against monthly energy consumption. Other residential schedules provide service to multifamily dwellings (Schedules EM and ES), mobilehome parks (Schedule ET), PG&E employees (Schedule EE), and customers agreeing to time-of-use service (Schedule E-7).

1. Residential Customer Charge

a. Positions of the Parties

DRA recommends replacing the current $5 minimum bill with a $3 customer charge. Revenues from the customer charge would be included in the Tier 1 rate calculation.

DRA argues that the current rate structure does not explicitly reflect the full costs of providing access to the system to residential customers. These costs get shifted to energy rates, and customers with high consumption bear a disproportionate responsibility for these access costs. The customer charge would promote efficiency by making a closer connection between the costs incurred and the costs paid for access to the system.

DRA performed an analysis that showed that a customer charge will have a moderate effect on residential customers. No customer receives a monthly increase of more than $3, and 60% of all customers receive either a decrease or an increase of less than 50 cents. In addition, DRA's proposal to include revenues from the customer charge in the calculation of the Tier 1, or baseline, rate moderates the increase for low-usage customers.

The adverse public reaction that has occurred in the past when residential customers charges were introduced could be mitigated by distributing educational material explaining the customer charge in the first billing reflecting the charge, DRA believes. DRA notes that the telephone and water industries assess fixed charges like the customer charge without any negative reaction from their customers.

DRA also puts forward an alternative proposal that would retain the minimum bill and add a customer charge of $1.50 or $2.

PG&E opposes DRA's recommendation. PG&E cites SDG&E's experience with its customer charge, which had to be withdrawn after seven months because of an outcry by customers. PG&E believes that customers will not accept a customer charge.

PG&E also rejects the recommendation to include revenues from the customer charge in the calculation of the Tier 1 rate. This proposal would completely violate the underlying marginal cost relationships between the tiers. DRA has failed to explain how the customer charge would interact with the low-income ratepayer assistance (LIRA) program or how the charge would be applied to master-metered customers, according to PG&E.

For similar reasons, TURN "strongly opposes" the customer charge. Residential rates have risen 18% over the last three years, and the higher bills that many customers would receive as a result of the customer charge would add to their burden. TURN opposes the charge because most residential customers would receive an increase, because low-usage customers would receive the largest increases, and because customers in temperate climates would receive disproportionate increases. TURN points out that many customers in temperate zones live in densely populated areas where the cost of access to PG&E's system is lower. Thus, the customers who impose the lowest access costs would bear proportionately more of the customer charge.

b. <u>Discussion</u>

For several years, we have supported an unbundling of electricity rates into various components to reduce cross-subsidization of various customer groups, so that the costs a customer causes the system to incur would be reflected in the customer's bill. We have expressed our support for the notion of a customer charge as a fair and efficient way of reflecting some of the fixed costs of access to an electric utility's system. We have several times indicated that we would adopt a residential customer charge when circumstances permitted.

Our experience with SDG&E's customer charge, however, has dampened our enthusiasm. We now recognize that customer acceptance is a consideration that should outweigh economic correctness in evaluating the customer charge. Our fears about customers' reactions to a $3 customer charge have not been assuaged by DRA's suggestion that educational materials would improve acceptance of a customer charge. For these reasons, we will not adopt the customer charge recommended by DRA.

We still think a customer charge, properly presented, could win the sort of customer acceptance that fixed and flat charges have received in the telephone industry. Rather than adopting a customer charge for all residential customers, however, we would prefer to see some pilot studies to determine customer acceptance of various levels and various presentations of the charge. We will not compel PG&E to perform these studies, but we will look favorably on proposals from PG&E or other energy utilities for such studies. We note that PG&E's proposed Schedule E-8 may provide information about residential customers' acceptance of a customer charge.

2. Baseline Issues

Residential rates are currently divided into two tiers with different rates. By statute, all residential ratepayers receive a minimum or baseline quantity of electricity at somewhat lower rates (Tier 1); consumption of electricity that exceeds the baseline quantity is priced at a higher rate (Tier 2). Several issues arose concerning the two-tiered residential rate structure.

a. Reduction of the Differential Between Tiers

Application of the baseline structure has had some unexpected effects that led the Legislature to direct the Commission to reduce Tier 2 rates as rapidly as possible (Public Utilities Code § 739.7). In D.88-10-062, we began implementing this legislation by reducing the percentage differential between Tier 1 and Tier 2 rates by 10%.

(1) <u>The Parties' Initial Positions</u>

PG&E proposes a further reduction of the differential between Tier 1 and Tier 2 rates by 50%. PG&E believes this reduction would continue to carry out the Legislature's intent, and the financial effect on individual ratepayers would be relatively small.

DRA proposes a tier differential reduction of 10%. The recent legislative revisions to the baseline statutes prohibit the Commission from substantially eliminating any significant differential between the tiers for 30 months from the bill's effective date of June 1988. DRA concludes that PG&E's proposed 50% reduction is inconsistent with the Legislature's directive. DRA's study showed that PG&E's requests for rate increases in this general rate case and its current ECAC case, when combined with its tier differential proposal, would result in a 25% bill increase for all customers who consume their baseline quantities or less. About 14% of this 25% increase directly results from the 50% decrease in the tier differential.

DRA believes its recommended 10% tier differential reduction complies with the Legislature's intent. While continuing progress toward reducing the tier differential, DRA's proposal maintains a substantial differential and avoids adverse rate effects.

DRA further urges that the change in rate differential be carried out as part of the change in PG&E's ECAC rates on November 1, 1989. PG&E believes that a change on January 1, 1990, along with other rate changes connected to the general rate case, would be more acceptable and comprehensible to its customers.

TURN opposes PG&E's proposed 50% decrease in the tier differential. TURN argues that the decrease in the differential should be no more than 10% and supports DRA's recommendation. TURN joins DRA in referring to the same legislation as PG&E but concludes that the required reduction in tier differential has already been accomplished. The rate increases shown in DRA's study of PG&E's proposal are unacceptable to TURN. Since the statute bars a substantial elimination of the tier differential for 30 months from June 1988, TURN concludes that the Legislature has essentially prohibited the 50% reduction proposed by PG&E.

(2) The Effect of D.89-09-044

On September 7, 1989, two days before the update hearings in this proceeding, we issued D.89-09-044 in I.88-07-009, our proceeding for complying with Senate Bill 987 (1988 Cal. Stats. Ch. 212). In that decision we adopted the Low Income Ratepayer Assistance (LIRA) program that granted eligible low-income residential customers a 15% reduction from the rates they would otherwise be charged. The reduced revenues and costs of administering this program are to be borne by other ratepayers by means of a surcharge. The decision directed that the determination of the LIRA rates and the amount of the surcharge should be part of this general rate case.

PG&E presented some testimony on the effect of D.89-09-044 on the issues in this case. Other parties were unable to respond during the update hearings, however, because the decision was not mailed until September 11. The ALJ allowed parties to brief the effect of D.89-09-044 on the issues in this case as part of a supplementary brief that followed the update hearings.

PG&E believes the decision strongly supports its original recommendation to decrease the tier differential by 50%. The Commission made clear that the existence of the LIRA program was tied to tier reduction, and it indicated its desire to close the differential in the very near future. Furthermore, the Commission explicitly stated that "the level of the adopted LIRA discount will cause us to accelerate the pace at which further realignment [of the tiers] occurs" (D.89-09-044, mimeo. p. 8). The 10% reduction in the tier differential proposed by DRA and TURN does not accelerate the pace of realignment; only PG&E's proposal meets the Commission's intent.

DRA disagrees with PG&E's conclusion. DRA points out that the Commission expressly declined to establish a timetable for reducing the tier differential. In addition, the Commission is governed by the statutory provision that requires a "significant differential" to be maintained between the tiers until the end of 1990. Customers who do not participate in the program and who do not exceed their baseline quantities will face substantial rate increases under PG&E's proposal. DRA believes its proposal best balances the intent of the Commission and the directives of the Legislature.

TURN contends that the decision on reducing the tier differential should be based on the requirements of SB 987 and the record in this case, not on a rash interpretation of D.89-09-044. The LIRA program is still new, and not all low-income customers will take advantage of it in the first year. By contrast, all low-income customers will be affected by PG&E's proposal. The 50% tier reduction proposed by PG&E will raise rates 14% for customers who limit their consumption to baseline quantities. PG&E's proposal effectively cancels out the rate reductions the Commission intended to grant in the LIRA program. "It makes absolutely no sense to give these customers a discount with one hand and take away with the other," TURN submits.

(3) <u>Treatment of Minimum Bill Revenues</u>

A collateral issue concerns DRA's proposal to include minimum bill or customer charge revenues in the calculation of the Tier 1 rate. PG&E opposes this proposal because it conflicts with the approach to calculation of the tier differential that the Commission has consistently followed, and because it leads to an increase in the existing tier differential, contrary to the instructions of the Legislature.

(4) <u>Discussion</u>

For several reasons, we believe substantial progress should be made at this time toward reducing the differential between Tier 1 and Tier 2 rates. The Legislature has clearly directed us to reduce high Tier 2 rates by reducing this differential, although it has also instructed us to proceed at a moderate pace in closing the gap until the end of 1990. Our determinations in D.89-09-044, as we indicated in that decision, provide a significant benefit to low-income customers that mitigates the effect of lower differentials between rates for the two tiers. Our action in that case allows a more rapid movement toward closing the spread between these rates. The 10% reduction proposed by DRA and TURN moves too slowly in light of these circumstances. As we have indicated, we will review our progress in reducing the tier differential in 1991, and we would like to avoid the need for drastic action at that time.

At the same time, we are concerned that PG&E's proposed 50% reduction would be too extreme. The Legislature has directed us to maintain a significant differential between the tiers for thirty months, and this direction suggests a more moderate reduction in the differential is appropriate at this time. In addition, DRA calculated that a 50% reduction by itself would result in a 14% increase for customers who limit consumption to baseline quantities, an increase that would nearly eliminate the LIRA program discount for low-income customers in this group.

We conclude that the differential between Tier 1 and Tier 2 rates, expressed in cents/kWh, should be reduced 25% in connection with this case. This reduction should take place on May 1, 1990, when baseline quantities are adjusted. This level of reduction will make considerable progress toward lowering the tier differential, but it will preserve some benefits for low-income customers whose consumption is at baseline quantities.

With the reductions in tier differentials we made in D.88-10-062 and this case, the difference between Tier 1 and Tier 2 has declined substantially. This reduction can be quantified in several ways, but all measures indicate that we now have moved about halfway to our goal of ensuring that "in the very near future the level of the LIRA discount [15%] and the size of the Tier 1/Tier 2 rate differential are essentially commensurate." (D.89-09-044, mimeo. p. 8.)

On other issues in this area, we conclude that the calculation of Tier 1 rates should include minimum bill revenues. Consumption by customers who pay minimum bills is predominantly within Tier 1.

b. Baseline Quantities

PG&E and DRA agree on four principles for the calculation of baseline quantities. First, baseline quantities should be established at the maximum allowed under Public Utilities Code § 739. Second, four years of billing data should be used to calculate the target quantities in this case. Third, in the next general rate case, temperature-adjusted data should be used instead of multi-year averages. Fourth, target quantities for master-metered dwelling units should be set by reducing the corresponding individually metered quantity by the ratio of master-metered usage to average individually metered usage by end-use, season, and climate zone. We endorse these principles.

PG&E agrees with DRA's proposed target baseline quantities, and we will adopt DRA's quantities (Exhibit 114, Tables 2-1 and 2-2).

PG&E should continue the current practice of adjusting baseline quantities every May and phasing in toward the target quantities we have just adopted. Rate levels should be adjusted at the same time to make the change in quantities revenue-neutral.

c. <u>Implementation of the LIRA Program</u>

As we have discussed, D.89-09-044 left several issues about how to carry out the LIRA programs to be resolved in this case.

(1) <u>Treatment of the Minimum Bill</u>

In D.89-09-044, which covered all regulated gas and electric utilities, we determined that the adopted 15% discount should also apply to the monthly customer charge for utilities who assess such a charge.

In this decision, however, we have determined that a residential customer charge is not appropriate at this time, and we will continue the use of a minimum bill. D.89-09-044 was silent on the treatment of the minimum bill under the LIRA program.

In its supplemental brief on the effects of D.89-09-044, PG&E presented a summary of its proposed rates that included a 15% reduction in the minimum bill as part of its rates for low-income customers.

Although other parties have not had an opportunity to comment on this treatment, we believe PG&E's approach makes sense. If the minimum bill were not reduced, the LIRA discount would be lost to low-income customers who consume less than the amount allowed by the minimum bill.

(2) <u>LIRA Discounts for TOU Customers</u>

In D.89-09-044, we specifically considered the application of the LIRA discount to PG&E's Schedule E-7, which offers TOU service to residential customers (mimeo. pp. 10, 16, 22, and 26). We determined that the best way to implement the discounts for low-income TOU customers was to waive the TOU meter charge.

(3) <u>Schedules EL-1 and EL-7</u>

In D.89-09-044, we directed utilities to offer the LIRA program discounts "in a tariff separate from the main residential tariff" (mimeo. p. 25). PG&E has indicated in its supplemental brief that it will set up new Schedules EL-1 and EL-7 to provide for the LIRA discount and to correspond to existing Schedules E-1 and E-7. We find that PG&E's proposed schedules meet the requirements of D.89-09-044.

(4) **Treatment of Low-Income Customers Served Through Master Meters**

The issue of how the LIRA program would be implemented for low-income customers served through master meters was addressed in D.89-07-062 and D.89-09-044.

In D.89-07-062 we determined that the LIRA program would be extended only to eligible submetered tenants served through a master meter. Other tenants are served through a master meter, but their consumption is not metered, and their energy bills and rent are not separated. We determined that these tenants would not be eligible for the LIRA discount, because there is no practical way to estimate their usage and to ensure that the discount would be passed through to them. D.89-09-044 clarified, but did not essentially alter, the determinations of D.89-07-062.

(5) **Exemptions from the Surcharge**

D.89-09-044 exempted existing sales made under special contracts with specific rates, sales to wholesale electric customers, sales to qualified low-income customers, and sales to streetlighting customers from the LIRA surcharge. The exemption for streetlighting customers was granted "because such service is ultimately paid for by taxpayers, who will already contribute to the LIRA program as ratepayers" (mimeo. p. 20).

Relying on the rationale stated for this exemption, PG&E proposes to exclude sales under Schedules LS-1, LS-2, LS-3, and TC-1 from the surcharge, but to include sales under Schedule OL-1. Schedule OL-1 provides outdoor lighting for customers other than governmental entities, and exempting sales under this schedule is not consistent with our stated reason for the exemption.

We agree with PG&E that sales under Schedule OL-1 should be subject to the LIRA surcharge.

(6) Calculation of the Surcharge

The calculation of the LIRA surcharge was described in D.89-09-044. In its supplemental brief, DRA provides a helpful illustration of how it proposes to perform this calculation. With the figures DRA assumes, the resulting surcharge is 0.04 cents/kWh. Without endorsing this precise rate, we believe DRA presents an illustration of the approximate level of the surcharge. The surcharge should be calculated by the method illustrated in DRA's supplemental brief, subject to the other determinations of this decision. The surcharge should be based on the rates that will become effective on January 1, 1990, and should also recover the discounts paid in November and December 1989 and other appropriate costs of this program.

3. Optional Residential Rates

a. Schedule E-7

(1) Positions of the Parties

Schedule E-7 is an optional time-of-use schedule that has been offered for several years. Parties made several recommendations concerning the relationship between on- and off-peak rates.

PG&E thinks the summer on-peak to off-peak ratio should be set at 80% of the full EPMC level, an approach that will have the effect of moderating increases to the summer on-peak energy rate. PG&E joins DRA in recommending a revenue allocation for Schedule E-7 separate from other residential customers. PG&E's proposed Schedule E-7 would eliminate the baseline credit.

DRA believes that all pertinent rate differentials--summer versus winter, on-peak versus off-peak, and their combinations--should move halfway from current relationships to EPMC-based differentials. Customers on Schedule E-7 would receive a baseline credit that sets the average Schedule E-7 baseline rate at the average Schedule E-1 baseline rate, minus Schedule E-7's meter charge prorated over the average baseline usage in DRA's proposal. A larger baseline credit, such as TURN recommends, is also acceptable to DRA. DRA also proposes a new rate option, Schedule E-9 (discussed below), that would be similar to Schedule E-7 but would not have a baseline credit.

TURN proposes a revenue-neutral on-peak rate.

PG&E supports its position by arguing that its recommendation, which produces a summer on-peak rate of around 26 cents/kWh as compared with DRA's 34 cents and TURN's 36 cents, helps keep this optional schedule attractive to current and potential participants. The other parties' proposals, PG&E argues, could lead to many drop-outs from the program and thus to much higher administrative costs.

PG&E finds TURN's proposal--to base the revenue allocation for Schedule E-7 on the usage characteristics of customers on Schedule E-1--to be illogical and against the practice and guidelines of this Commission. Although TURN promotes its approach as being revenue-neutral, PG&E calculates that the average rate for a typical Schedule E-7 customer will be much higher than the average Schedule E-1 rate if TURN's proposal is adopted. Moreover, TURN's approach ignores the fact that customers with high energy consumption have a lower average cost of service than low-use customers, a relationship that PG&E believes should be reflected in rates for Schedule E-7.

PG&E also opposes DRA's and TURN's proposals to include a baseline credit for Schedule E-7. Such an approach was adopted in PG&E's last general rate case, but the Commission had to modify its details twice to avoid undesirable effects. Under current rate design practices, it is possible and not unlikely that the baseline rate, as proposed by DRA and TURN, would actually exceed Schedule E-7's off-peak rate, leading to a nonsensical negative baseline credit.

DRA justifies its recommendations by pointing out that its proposals are much more favorable than PG&E's for low-usage customers. The Commission has indicated its interest in making TOU programs attractive to low-usage customers, and incorporating a baseline credit is a primary way to achieve that goal, DRA believes. PG&E's proposals penalize low-usage customers, because offsetting the monthly meter charge requires substantial minimum consumption. To the extent that customers think a TOU schedule without baseline credits will benefit them, DRA's proposed Schedule E-9 (discussed below) will meet that need.

TURN thinks both PG&E's and DRA's proposals are "seriously flawed." These proposals allow large users to save money even if their on-peak consumption exceeds the average residential consumption. TURN believes that TOU rates should encourage customers to reduce on-peak consumption, not reward large users for high consumption.

TURN cites two basic flaws in other parties' proposals. First, both DRA and PG&E use a separate revenue allocation for Schedule E-7. Because of this separation, less revenue is allocated to other residential users, and customers on Schedule E-7 receive lower rates while Schedule E-1 customers bear higher rates. The second flaw is the proposal to reduce or eliminate the tier differential, which reduces large users' bills because of their larger consumption in Tier 2.

TURN believes its proposal would create the proper incentive to encourage customers to use electricity efficiently and to discourage on-peak consumption. TURN's proposal for Schedule E-7 includes a single revenue allocation for the residential class and a full baseline credit. TURN contends that its proposal is revenue-neutral because customers with the same on-peak usage as the class average would essentially pay the class average rate (except for the added costs of the TOU meter), and only customers who shift load to off-peak periods would see significant savings.

TURN acknowledges that its proposal may lead to increases for existing TOU customers. To mitigate the effect of these increases, TURN proposes that the initial revenue allocated to Schedule E-7 would be limited to 5% above the residential class average percentage change.

(2) <u>Discussion</u>

The parties' positions on this issue place slightly different emphases on the function of residential TOU rates. PG&E and DRA tend to emphasize the importance of TOU rates in communicating accurate pricing signals to customers; customers on Schedule E-7 face a high summer on-peak rate, corresponding to the high costs of producing power during those periods, and the customer can then decide to incur those costs or forego the use of electricity during those periods. TURN, on the other hand, emphasizes that TOU rates should primarily be designed to shift consumption away from on-peak hours. TURN sees TOU programs as a type of load management program, rather than an informational program.

The consequences of these two emphases can be illustrated by the parties' apparent attitudes toward the composition of the subclass of customers on Schedule E-7. PG&E and DRA seem to accept that this schedule will attract more high-usage customers, who can reduce their overall bills by converting to this schedule. PG&E and DRA find the schedule's attraction for high-usage customers acceptable, provided that these customers are paying an accurate price for their consumption. In this respect, DRA and PG&E approach residential TOU rates like TOU rates for other customer classes, where we require large customers to take service on TOU schedules.

TURN, by contrast, argues against creating what amounts to a separate subclass for high-usage residential customers. TURN's proposal is designed to make Schedule E-7 more attractive to customers of all levels of consumption and to encourage shifting of consumption from on-peak to off-peak periods.

Obviously, these two emphases overlap considerably. At this time, in keeping with our recent rate design policies, we believe it is appropriate to emphasize the dissemination of accurate cost information through rates. We believe that accurate information will inevitably have a great effect on shifting consumption to off-peak periods.

At the same time, we want to maintain the option for low-usage customers to take advantage of the TOU option, if they can shift consumption to off-peak periods. We believe that retaining a baseline credit for Schedule E-7 will make this option more attractive to these customers.

Of the proposals put before us, we find that DRA's has more of the characteristics we desire for Schedule E-7. A capped EPMC approach to revenue allocation to Schedule E-7 should continue to be used. We disagree slightly with DRA on the calculation of the baseline credit for Schedule E-7. We find it conceptually preferable to derive the Schedule E-7 baseline credit from the difference between Schedule E-1's Tier 1 and Tier 2 rates, minus Schedule E-7's meter charges prorated over the average baseline usage. This approach should avoid some of the problems that have arisen in the past, as pointed out by PG&E, particularly as we narrow the differential between the tiers. To avoid a repetition of those problems, the baseline credit should be limited so that Schedule E-7's off-peak rate goes no lower than marginal cost (see D.87-12-033, p. 31).

The parties' recommendations on modifications to on- and off-peak differentials are calculated on a different basis and are slightly confusing. PG&E recommends moving the summer on-peak to off-peak ratio to 80% of the EPMC level; DRA argues for moving all TOU and seasonal differentials 50% of the distance from current differentials to EPMC levels. But because of the current levels of these differentials, DRA's recommendation brings the summer on- to off-peak ratio closer to EPMC levels. DRA's proposals provide better information about costs to customers on Schedule E-7. We therefore endorse DRA's proposal to move all seasonal and TOU differentials halfway to EPMC-based levels.

Although we have not adopted its proposals, we recognize that TURN has raised an important concern about residential TOU rates. We invite parties to consider how TOU schedules can be made attractive to low-usage customers, how to ensure that these schedules do not merely serve as a subsidy for high-usage customers, and how to maintain equity between customers on Schedule E-7 and those who must remain on Schedule E-1. These topics may be addressed during the next proceeding when rate design issues are considered.

b. Schedules E-8 and E-9

(1) Positions of the Parties

PG&E proposed a new residential rate option with a customer charge based on full EPMC, seasonally differentiated energy charges, and no baseline credit. The purpose of this new Schedule E-8 is to offer a response to bypass by customers who use wood and propane to heat their residences. DRA supports PG&E's proposal, but PG&E thinks DRA's projection of average consumption under Schedule E-8 leads to an unacceptably high summer rate. PG&E believes the summer rate for Schedule E-8 should fall between the Tier 1 and Tier 2 rates for Schedule E-1 to arouse sufficient customer interest.

DRA proposes a new Schedule E-9 that resembles Schedule E-7. However, the new schedule would have a customer charge based on full EPMC, energy rates derived from EPMC-based seasonal and TOU differentials, and no baseline discount. DRA believes Schedule E-9 answers many of PG&E's concerns about its proposals for Schedule E-7 and offers an attractive alternative that many customers, particularly high-usage customers, will choose. PG&E opposes DRA's proposal on the grounds that the new schedule is unnecessary, has an extremely limited potential market, and will create confusion among residential customers.

TURN opposes both PG&E's and DRA's proposed rates. The proposed schedules have high customer charges, lack a baseline credit, and are based on a separate revenue allocation that will benefit only large users.

If a rate is needed to compete with wood or propane for the winter heating market, TURN thinks PG&E should offer an option similar to one used by Pacific Power and Light Company (PP&L). This option establishes a base period for each winter month's consumption and offers discounts for consumption above the base amount. The option also requires the customer to install certain weatherization measures. TURN thinks the resulting discounts would appeal to customers heating with wood and propane. Any revenue shortfall should be allocated like the shortfall from special contracts with industrial customers, TURN urges, with lost revenues recovered from other customer classes.

PG&E and DRA oppose TURN's proposal. PG&E notes that PP&L has been forced to make several modifications to its experimental rate and that the Commission has concerns about whether the rate actually led to increased electricity consumption for heating (Res. E-3160). DRA pointed out that TURN's proposed rate does not have a floor that includes the marginal cost of noncoincident capacity and that TURN's witness could not testify that the proposed rate corresponded to the indifference rate of a customer heating with wood or propane.

(2) Discussion

We will approve a new Schedule E-8. We have doubts about the effectiveness of TURN's proposed option in accomplishing its intended purpose, and we are reluctant to approve this type of option until PP&L's experimental rate has demonstrated greater success. Schedule E-8 is a reasonable and administratively simple effort to compete for customers who heat with wood or propane.

We agree with DRA, however, that PG&E's projections of consumption by customers on this schedule are too low. Rate design for this schedule should assume the average consumption estimated by DRA and include a customer charge and seasonal energy rates set at full EPMC levels. In addition, to prevent tariff-shopping and excessive switching between Schedules E-8 and E-1, the tariff for Schedule E-8 should have a special condition requiring customers who choose this option to remain on this schedule for at least one full year.

We will not approve the proposed Schedule E-9. DRA has projected that this schedule will attract only 1,490 customers in 1990. This small degree of participation does not outweigh the potential confusion that a new residential TOU option could create. As our decision on Schedule E-7 rates indicates, we believe it is important at this time to maintain a degree of stability in our residential TOU program.

4. Master-Meter Discounts

a. Introduction

PG&E provides electric and gas service through master meters to mobilehome parks and multifamily dwellings with submetered service to their tenants under Schedules ET and GT (mobilehome parks) and Schedules ES and GS (multifamily dwellings). PU Code § 739.5 requires master-meter customers who provide submetered service to tenants of mobilehome parks, apartment buildings, and similar residential complexes to charge the tenants the same rate that the utility would charge if it provided direct service. Because submetered service allows the utility not to incur some of the distribution and customer costs that are included in its rates, Section 739.5 further states:

> "The commission shall require the corporation furnishing service to the master-meter customer to establish uniform rates for master-meter

> service at a level which will provide a sufficient differential to cover the reasonable average costs to master-meter customers of providing submeter service...."

We have implemented this statute by basing master-meter discounts on the average costs PG&E incurs in serving residential layouts similar to those served by the master-meter customer.

PG&E presented testimony and studies to support its quantification of the master-meter discount, and DRA and TURN base their recommendations to a large extent on these studies. WMA disputed the accuracy of and the basis for PG&E's studies on mobilehome parks and presented recommendations supported by its own research. The dispute over the calculation of master-meter discounts for mobilehome parks covered four topics. The discounts for submetered multifamily dwellings, served on Schedules ES and GS, were not contested in this case.

b. <u>Plant Cost Studies</u>

PG&E conducted a review of the previous cost studies that supported its existing master-meter discounts and determined that the old studies had several key defects. PG&E therefore decided to conduct new cost studies and to develop its proposed master-meter discounts from them. Both the former gas and electric studies exaggerated the length of the distribution system of a submetered mobilehome park, and the electric studies included the costs of a portion of PG&E's distribution system that was not provided by the master-meter customer.

WMA disputes the accuracy of PG&E's cost studies. The new studies bear no relationship to the studies that the Commission has relied on in the past. PG&E deviated dramatically from accepted procedures in conducting its studies, and it has not demonstrated that its results are in any way superior to past studies, according to WMA. PG&E used unreliably small samples and violated the basic requirements of random sampling methods, WMA argues. In addition, PG&E applied an index inappropriately to develop an estimate of historic plant costs.

For all these reasons, WMA believes PG&E's studies should be rejected. The cost studies from PG&E's last general rate case should be updated, and the master-meter discounts derived from them.

DRA essentially supports PG&E's approach but has reservations about the validity of the samples underlying the cost studies. Because of those reservations, DRA calculated the portion of average rates that can be attributed to the cost of distribution and customer accounts and compared the resulting ratios to the portion of average bills on the master-meter schedules attributable to the master-meter discounts (which reflect distribution and customer account savings).

DRA concluded that PG&E's proposed discounts are reasonable, except for the Schedule GT discount, which DRA thinks should remain at its present level.

TURN supports DRA's suggestions, including the recommendation to maintain the discount for Schedule GT at current rates. TURN notes that a large number of the bills under Schedules ET and GT do not even cover PG&E's fuel costs. This poses a substantial burden for other customers, which TURN does not believe should be increased.

It is obvious from the criticisms of other parties that PG&E's cost studies have many shortcomings that could affect their accuracy. Nevertheless, we will adopt discounts based on those studies and on DRA's analyses. DRA's somewhat rough check of PG&E's figures lends some credence to PG&E's results except for Schedule GT. We agree with DRA that the discount for Schedule GT should not be changed at this time.

Our reason for accepting PG&E's figures comes from the collateral testimony about the levels of average rates for master-meter customers. PG&E testified that over 36% of the Schedule ET bills had average rates that were less than or equal to the ECAC rate, and 27% of the Schedule GT bills had average rates that were less than or equal to the core weighted average cost of gas (WACOG) rates. These rates express PG&E's direct cost of purchasing fuel and electricity, and in theory the discounted master-meter rates should always be higher than this level. The fact that some bills are lower than the cost of fuel indicates that the existing discounts are skewed, and that some master-meter customers are subsidized by other customers. For this reason, we are reluctant to raise the discounts above the levels recommended by DRA.

Section 739.5(a) effectively limits the costs that are the basis for the discount by providing that "these costs shall not exceed the average cost that the corporation would have incurred in providing comparable services directly to users of the service." For purposes of this discussion, the utility's product can be divided into two services, providing energy and arranging for the customer's access to the utility's system. The master-meter customer who submeters its tenants replaces the utility in providing access to the utility's system, and the utility's cost of providing this comparable service sets the limit for the discount.

It is immediately obvious that the master-meter customer does not provide energy services. If the discount results in a rate that does not equal the utility's cost of providing these energy services, elementary arithmetic shows that costs underlying the discount exceed the utility's average cost of providing customer access.

The statistics on the percentage of master-meter customers with average rates less than the ECAC or WACOG rates, combined with the somewhat shaky basis for the master-meter discounts, leads us to adopt a safeguard to ensure that the limitations of Section 739.5(a) are observed. As we have just discussed, master-meter customers, like other customers, should bear at least the costs of the energy required to serve them, and any discounts that result in rates lower than the ECAC and WACOG rates are clearly too high. We will therefore adopt a minimum average rate for master-meter customers equal to the average ECAC rate for Schedule ET and the core WACOG for Schedule GT. This minimum rate should be collected from master-meter customers even if master-meter discounts would result in a lower bill.

These facts also lead us to question the approach that has been employed to calculate master-meter discounts up to now. We will again instruct PG&E to reexamine the basis for its cost studies and to put extra effort into developing an accurate and easy-to-verify method for calculating the master-meter discounts. The results of its efforts should be reported as part of its next general rate case application.

c. Vacancy Factor

PG&E and WMA apply the vacancy factor in different ways.

PG&E uses a vacancy factor to reduce the component of the discount associated with customer accounts. PG&E reasons that the master-meter customer does not incur customer accounts-related costs, such as billing and meter reading, when a space is vacant. PG&E reduces the master-meter discount to reflect these savings.

WMA applies the vacancy factor to the investment the master-meter customer has made in the equipment that provides service to the tenants. WMA argues that the discount should be increased to compensate the master-meter customer for the investment costs that are not recovered when no tenant is occupying a space. To put the master-meter customer in the same shoes as the utility, WMA argues, compensation for these sunk and unrecovered investment costs is necessary.

PU Code § 739.5 requires the net master-meter discount to be based on "the reasonable average costs to master-meter customers of providing submeter service." Thus, the amount of the master-meter discount should be the answer to the question of what are the reasonable average costs of providing submeter service. The adjustment PG&E makes to customer accounts expenses appears to be consistent with the language of the statute and with PG&E's calculation of the discount on an occupied space basis. It is not obvious that the adjustment proposed by WMA also needs to be made. But we agree with WMA that the discount should be calculated on a consistent basis. Because PG&E calculates the discount on an occupied space basis, the underlying plant cost and other components should reflect an average vacancy rate. We believe the language of the statute dictates this result.

d. Diversity Factor

Master-meter customers receive baseline quantities for all of their submetered tenants. Some of these tenants may consume less than the baseline quantity that is allotted to them and other tenants' consumption may exceed their allotment. The master-meter customer could benefit unfairly from the diversity of the tenants' consumption patterns by purchasing some power at Tier 1 rates and reselling it at Tier 2 rates. A diversity factor is calculated and applied to reduce the discount to avoid inequitable discounts for the master-meter customer.

WMA criticizes PG&E's diversity studies, but it is willing to use the results of these studies in its discount proposal. PG&E agreed to recalculate the diversity benefit adjustment to reflect the baseline quantities and rates that result from this case and related proceedings.

PG&E's agreement to recalculate the diversity benefit adjustment is a reasonable resolution of this issue.

e. Electric Line Loss Adjustment

In PG&E's last general rate case, WMA introduced evidence about the line losses from the master meter to the submeter. WMA argued that its estimated line losses should be considered in the calculation of the master-meter discount. We rejected WMA's figures, but we agreed that line losses should be taken into account in developing a reasonable discount for submetered mobilehome parks. We directed PG&E "to conduct a study in conjunction with WMA to determine the actual line losses of submetered mobilehome parks." (D.86-12-091, mimeo. p. 37.) The results of this study were to be presented as part of this case.

For various reasons, the joint study contemplated in D.86-12-091 was not undertaken. WMA objected to PG&E's evidence on line losses, and the ALJ directed the parties to develop a joint study, as had been previously ordered by the Commission. The resulting joint study, Exhibit 94, was considered as part of the update hearings.

Because of the time constraints, Exhibit 94 is based on a limited sample of submetered parks. Line losses were calculated by reviewing billing data for the master meter and submeters and estimating common area usage from visits to the parks. Of the five parks selected, one park was dropped from the study because submeter billing data was not available, and one park was excluded because the estimates resulted in an improbable negative line loss. The average estimated line loss for the remaining three parks was 5.06% of master-meter consumption.

(1) PG&E's Position

PG&E believes that the study summarized in Exhibit 94 is flawed and should be rejected by the Commission. PG&E supports the results of its original study, set forth in Exhibit 17 and revised in Exhibit 85. In its original study, PG&E reviewed five distribution systems in mobilehome parks of different sizes and ages. PG&E calculated line losses based on the equipment installed in the parks and the billing data for the parks. The resulting line losses are 0.49% of master-meter consumption, and the corresponding adjustment to the discount is $0.25 per space.

PG&E criticizes the study presented in Exhibit 94. Several sources of error are possible, including the metering equipment. The estimates of consumption in common areas is subject to estimating error and imprecisions of automatic equipment governing electricity usage in those areas. Distribution systems in the parks may not meet PG&E standards, leading to unnecessarily high losses. Losses for PG&E's entire secondary distribution system, including transformation from the primary to secondary level, average 3.61%, well below the results of the study. Finally, in interpreting the study's results, PG&E subtracts the losses in master-meter transformers in performing the calculation of the discount. WMA believes these transformer losses should not be considered in the adjustment, because mobilehome parks are not served through a master-meter transformer.

(2) <u>WMA's Position</u>

WMA supports the results of the study presented in Exhibit 94. WMA thinks PG&E's criticisms have been refuted, and it believes the results of the study are reasonable when compared to other available information. PG&E's previous estimates were entirely based on engineering formulas, and the results were never tested against actual losses by directly metering the losses associated with a submetered park. WMA would prefer to perform a year-round metering of a reasonable sample of mobilehome parks to develop reliable estimates of line losses, but because PG&E has not complied with the Commission's directives, such a study was never undertaken. In the absence of such a study, the study presented in Exhibit 94 is the soundest estimate that can be made at this time.

(3) <u>DRA's Position</u>

DRA notes that it had earlier expressed its concern about the small sample size that PG&E used in conducting its survey of mobilehome parks. The study of Exhibit 94, however, is based on an even smaller sample, making its results suspect. DRA states that the results of some of PG&E's studies are in line with estimates of losses for the secondary system as a whole. DRA finally notes that the study ordered in D.86-12-091 to measure actual line losses has still not been performed.

(4) Discussion

We find that there are many defects in all the studies presented in this case. Because of an unexplained and completely counterproductive animosity between PG&E and WMA, the study we ordered in D.86-12-091 was never performed. PG&E's proposed study is based solely on formulas that may not prove accurate when applied to a complex submetering system, and PG&E has made no effort to verify its estimates. The study of Exhibit 94 is based on only three parks, and its soundness is brought into question by the negative line loss found for one of the other parks surveyed. We cannot base the adjustment on studies of this quality.

Our options are not attractive. Three years ago we determined that line losses should be taken into consideration in developing master-meter discounts. We still have no solid estimates of those line losses. We are reluctant to continue to have no allowance for line losses, because all parties agree that some losses occur.

We have searched the record, and we will adopt a line loss suggested as a temporary figure by WMA's witness. Earlier in this proceeding, he suggested that line losses could be based on the annual average secondary distribution level loss adjustment PG&E used in its marginal cost studies in this case (Exhibit 242, p. 12). This figure, 2.098%, has appeal because it was developed by PG&E and its temporary use was advocated by WMA. In addition, as an estimate of mobilehome park line losses, it seems to bear a reasonable relation to PG&E's losses for its entire secondary distribution system, 3.61% (Tr. 66:7095). For lack of a better figure in this record, we will adopt a line loss percentage associated with submetered mobilehome parks of 2.098%.

WMA and PG&E now agree that line losses occur primarily in the second tier of residential rates, and that the adjustment should be based on Tier 2 rates. DRA, however, thinks most mobilehome usage occurs within Tier 1, and it supports PG&E's former position that the adjustment should be based on a weighted average of Tier 1 and Tier 2 rates. PG&E's study shows that the marginal consumption of 9 of the 23 parks studied, or 39%, was within Tier 1 and that roughly 80% of total consumption was within Tier 1 (Exhibit 17, p. 3-10). PG&E's data refutes its current position. We will adopt DRA's approach of basing the adjustment on a weighted average of Tier 1 and Tier 2 rates. The weighting should be based on the data from Exhibit 17, p. 3-10.

Better studies are obviously needed. We will once again direct PG&E to develop studies of line losses of submetered mobilehome parks. Although we will not require that this study be exclusively based on actual measurements of line losses, it appears that a reasonable and statistically significant sample of submetered parks will have to be subject to actual loss measurements to resolve this question. PG&E should consult with WMA in developing its study, but we want to make it clear that we will hold PG&E responsible for coming up with an accurate and theoretically defensible study. The results of this study shall be presented as part of PG&E's next general rate case.

f. <u>LIRA Discounts for Submetered Tenants</u>

As we have previously discussed, the LIRA discounts implemented in this decision should be made available to submetered tenants of master-meter customers, but not to unmetered tenants served through a master meter.

g. <u>Conclusion</u>

Based on the determinations we have made in this decision, the master-meter discounts should be $10.50 per space per month for Schedule ET, $2.85 per space per month for Schedule ES, $6.32 per space per month for Schedule GT, and $3.60 per space per month for Schedule GS.

5. Submetering for Recreational Vehicle Parks

In D.88-09-025 we addressed the issue of submetering for tenants of recreational vehicle (RV) parks. In that case, several RV parks had asked the Commission to require PG&E and another utility to open up their mobilehome park master-meter rate schedules to RV parks. We determined at that time that RV parks could qualify for baseline allowances if they rent at least 50% of their spaces on a month-to-month basis for at least nine months of the year. RV parks that meet these criteria are also eligible for service on Schedule EM, and RV parks are eligible to have permanent tenants of the parks served directly by PG&E. We also declared that RV parks were eligible for service under general service or commercial schedules, and ruled that RV parks were not eligible for service under Schedule ET.

a. Positions of the Parties

CTPA seeks to alter the earlier determinations of D.88-09-025. It argues that the requiring nine months' occupancy is burdensome, and this requirement has left virtually all of its members and their tenants ineligible for baseline allowances. CTPA urges that RV parks should be permitted to submeter extended stay tenants who sign a rental agreement for a term of at least 30 days and to bill these tenants under Schedule E-1. The park owners would be billed under Schedule ES, which applies to multifamily dwellings.

CTPA believes this change is necessary because of the changing nature of occupancy in RV parks. More Californians are using RVs as their permanent residences, and occupancy in the parks is becoming more stable. The existing prohibition against submetering prevents the park owner from basing charges on electricity usage, which in turn discourages conservation and encourages waste. In addition, CTPA finds the current arrangement inequitable because the parks' tenants are effectively denied the benefits of baseline rates that other residential customers receive.

PG&E opposes CTPA's proposals. It believes CTPA is unjustifiably relitigating issues that were resolved in D.88-09-025. CTPA has submitted no new evidence that would warrant revising these issues and has not demonstrated that the existing provisions are unworkable. If few parks qualify under the existing requirement, PG&E contends, that merely shows that RV parks continue to be predominantly transient, and thus commercial in nature. The Commission has consistently excluded commercial customers from receiving residential baseline allowances.

DRA also opposes CTPA's requests. DRA believes CTPA may be misinterpreting the requirements established in D.88-08-025. CTPA seems to read the nine-month requirement to refer to continuous occupancy by the same tenant; DRA reads the decision to refer to the same space. In other words, DRA believes that the Commission intended that a park would devote a particular space for at least nine months of the year to occupancy by one or more tenants on a month-to-month basis, but several tenants could sequentially occupy the same space. A similar restriction applies to the rooms of residential hotels, and the RV park space is analogous to the room of a residential hotel. DRA asks us to clarify this ambiguity. If the Commission endorses DRA's interpretation, DRA recommends maintaining the existing requirement.

TURN sees no need for any changes to the Commission's existing policy as expressed in D.88-09-025. TURN opposes CTPA's proposals.

b. <u>Discussion</u>

CTPA has not persuaded us that the policy we developed in D.88-09-025 needs to be modified at this time. CTPA's assertions about the increasingly permanent nature of occupancy in RV parks is contradicted by its testimony about the impracticality of our qualifications for receiving baseline allowances. Our current requirements do not seem unduly restrictive, and if parks cannot meet them, this strongly suggests that their occupants are largely transient.

We note that similar requirements were established in D.83-12-068 for baseline allowances for residential hotels, and the record does not indicate that these establishments have had a similar problem in meeting these criteria.

As DRA points out, part of CTPA's problem may be solved by a clarification of the criteria of D.88-09-025. Although our language could perhaps be misinterpreted, our standard refers to spaces, rather than into individual tenants. Thus, if an RV park rents at least 50% of its spaces on a month-to-month basis to one or more tenants for at least nine months of the year, then the tenants of such spaces should be considered permanent residents who are also eligible for baseline allowances. (We note that PG&E's current Schedule EM refers to spaces, as we intended.) This clarification is close to one of the changes CTPA requested, but in all other respects, its requests are denied.

Although we reject the bulk of its request, CTPA has raised several points that may give rise to further action. CTPA has pointed out that tenants of RV parks have no incentive to conserve energy unless their individual consumption is metered and billed to them. In addition, CTPA has presented testimony that many park owners have installed submetering systems, despite our prohibition against new submetering systems. We would like better information on these points before we consider any further action on CTPA's requests. PG&E should work with CTPA to develop a survey of RV parks to determine: 1) the proportion of parks that meet our criteria for qualifying for baseline allowances, as set forth in D.88-09-025; 2) the proportion of parks that have installed submeters for at least some of their spaces; and 3) the proportion of RV park spaces that are rented on a month-to-month basis.

PG&E should submit this information, ideally in the form of a joint report with CTPA, with exceptions or dissents, if necessary, on or before January 1, 1991.

C. Small Light and Power

This category offers several service options for small commercial and industrial customers. Schedule A-1 is a general service schedule. Schedule A-6 offers a TOU option, and Schedule A-15 provides for direct current service. Schedule TC-1 covers traffic control service. Two issues concerned rates for service to this class.

1. Customer Charge

PG&E recommends increasing the customer charge for these schedules by 15% of the difference between current charges and marginal cost. The effect of PG&E's recommendation is to raise the monthly customer cost from $5.00 to $7.50. DRA would increase the customer charge by 7.5% of the difference between current charges and the EPMC level. DRA's recommended monthly charge is $7.00. As we have mentioned, ACWA urges that customer charges should be set at marginal cost, rather than EPMC, and that increases should be limited to 5% per year. The monthly charge apparently resulting from ACWA's recommendation is $5.25.

All parties agree that current marginal customer costs are well above the levels of the current charge or the charges recommended in this case. We agree with DRA and PG&E's general principle that customer charges for commercial and industrial customers should collect a greater share of marginal customer costs. We will therefore adopt PG&E's proposed charge of $7.50, which is only slightly higher than DRA's recommended monthly charge. ACWA's recommendation does not make adequate progress toward either marginal cost or EPMC.

2. Facilities Charge for Schedule A-15

DRA recommends raising the facilities charge for customers receiving direct current service under Schedule A-15 from

$6.00 per meter per month to $7.80. DRA argues that it demonstrated in PG&E's last general rate case that the costs of replacing direct current meters would be equalized over time at $7.80 per month. The Commission granted a substantial increase in these charges in the last general rate case decision, but DRA believes that this process should be completed in this decision.

PG&E does not oppose DRA's recommendation.

We will adopt DRA's recommendation and set the facilities charge for customers on Schedule A-15 at $7.80 per meter per month.

D. Medium Light and Power

These schedules provide service to mid-sized commercial and industrial facilities. Schedule A-10 provides an alternative to Schedule A-1 for customers with larger consumption of electricity and features higher customer charges, a maximum demand charge, and lower energy charges. Schedule A-11 is a TOU option. The level of some charges to these customers depends on whether the customer connects to PG&E's system at the primary distribution or secondary distribution level.

1. Customer Charges

The parties recommend the same percentage increases to current customer charges as were discussed under the customer charge for the small light and power class. PG&E recommends setting the monthly customer charge at $60.00, rather than the current $50.00, and DRA recommends an increase to $63.00. (Although DRA recommends a smaller percentage of movement, the goals of the two parties' movements are different; PG&E gears its recommendation to marginal cost, but DRA aims at the higher EPMC level.)

As with the small power and light class, the recommended customer charges are well below estimates of marginal costs. Because of the importance of continuing progress toward EPMC, and because the difference between the parties' recommendation is minor, we will adopt DRA's recommended customer charge of $63.00 per month for Schedules A-10 and A-11.

2. Energy Charge for Schedule A-10

PG&E proposes to establish a two-tier energy charge for Schedule A-10 instead of the current flat rate. The tiers would be based on load factor, measured on a kWh/kW basis. The first tier, defined as the first 280 kWh/kW per month, carries a higher rate. The second tier covers higher consumption levels and has a lower rate. Thus, higher load factor customers with greater consumption in the second tier would have a lower average rate.

PG&E offers four reasons to support its proposal. First, the rate structure mimics a TOU rate for high load factor customers. Second, the proposal encourages low load factor customers with little on-peak use to migrate to Schedule A-11. Third, it gives customers an incentive to improve their load factors. And fourth, it responds to potential bypass by increasing average rates for on-peak consumption by low load factor customers and reducing on-peak rates for high load factor customers.

DRA opposes PG&E's proposal. DRA submits that the proposed declining block structure is inconsistent with cost-based rate design principles and with conservation policies. Moreover, the structure of the proposed rate does not mimic TOU rates, as PG&E claims. The energy rate declines after the first 280 kWh/kW per month, no matter when that usage occurs. DRA believes that the proposed rate has the potential to encourage on-peak use, unlike a true TOU rate. PG&E has stated that customers on Schedule A-10 have a load shape that coincides with system peak. Encouraging greater usage, by lowering rates for higher consumption levels, will likely lead to more consumption with the same load shape, and thus to more on-peak usage, rather than improved load factors. Finally, DRA notes that a true TOU option exists in Schedule A-11. Encouraging conversions to that schedule would accomplish all of PG&E's goals without tampering with existing rate structures.

SCC and DGS also oppose PG&E's proposal. SCC and DGS echo many of DRA's concerns and point out that a similar proposal was rejected in SDG&E's recent general rate case (D.88-12-085, mimeo. p. 47). PG&E's proposal would encourage wasteful additional consumption and discourage conservation. Because the proposal has many undesirable side effects, and because a TOU option, Schedule A-11, is available to medium light and power customers, SCC and DGS urge the Commission to reject the proposal.

PG&E's proposal seems to be an attempt to encourage shifting of consumption to off-peak periods by customers with usage levels that do not justify TOU meters. By creating an incentive for the customer to improve its load factor, either by shifting load or by decreasing maximum demand, PG&E believes this rate structure will lead to a decrease in coincident capacity costs for this schedule.

We are not persuaded that PG&E's proposal is the most effective way of achieving its goals. The price signal that PG&E's provides is indirect, fairly sophisticated, and ambiguous. The customer may interpret this schedule as a signal either to reduce demand or to increase overall consumption. We hope to encourage the former behavior, but not necessarily the latter. For an individual customer with primarily off-peak usage, moreover, the schedule may be inequitable, as we pointed out in D.88-12-085. A more pointed way of improving load factor may be to increase the maximum demand charge and to inform customers of ways to reduce their recorded maximum demand. In any event, PG&E's proposal leaves us with too many unanswered questions about its actual, as opposed to its intended, effect, and we will not adopt it.

3. Conjunctive Billing Experiment

In D.86-12-091 in PG&E's last general rate case, we required PG&E to offer conjunctive billing to schools. Conjunctive billing refers to the practice of combining meter readings from multiple meters of a single customer to gain various rate benefits.

PG&E has offered two options for conjunctive billing. The first, the Existing Metering Option, combines the total use recorded by several meters and applies the most advantageous schedule for which the combined use qualifies. The second option, the Facility Allocation Option, calculates the customer's maximum demand from the combined diversified demand from several meters, rather than the sum of the maximum demands from the separate meters. Unless maximum demand is reached at the same time on all the meters, use of the diversified demand from the separate meters will result in a lower maximum demand and lower demand charges.

Conjunctive billing differs from summary billing, which presents on a single bill the charges from several meters serving the same customer.

PG&E proposes to end its conjunctive billing experiment. Of the 219 bill comparisons PG&E prepared for customers who inquired about conjunctive billing, only two have actually selected a conjunctive billing option. The minimal response persuades PG&E that schools have little interest in conjunctive billing, and that the expense of this program is not justified. PG&E will honor its existing contracts for conjunctive billing and will continue to offer summary billing to all customers.

Edison supports PG&E's request to discontinue the experiment, and Edison further asks the Commission to suspend Edison's comparable program.

Edison points to PG&E's testimony that the administrative costs incurred so far in pursuing this experiment exceed the benefit received by the two participants. Edison also performed an analysis of how PG&E's options would benefit schools in Edison's territory. It concluded that neither option offered by PG&E would result in enough savings for schools to offset the administrative costs of setting up and running a conjunctive billing program. Few schools would benefit, and the benefits to those few schools would be small.

SCRUB opposes ending this program. SCRUB points out that the first workbooks on conjunctive billing were not mailed to schools until February 1988. PG&E's request for discontinuance was based on the response as of August 8, 1988. In light of the complexity of making bill comparisons for the Facility Allocation Option, the only true conjuctive billing option, SCRUB thinks it is premature for the Commission to abandon this program based on less than six months of data on the targeted customers' response to the experiment. SCRUB urges the Commission to give this program more time and not to end it prematurely.

We agree with SCRUB that this program should be given more time to prove its worthiness. We will direct PG&E to continue its conjunctive billing experiment until at least December 31, 1990, and to work with SCRUB during this time to attempt to get responses to the experimental offerings from more schools. If PG&E concludes that this experiment is not cost-effective at the end of 1990, it may apply again to end the program as part of the next rate design window occurring after 1990.

In this proceeding, which concerns only PG&E, we will not grant Edison's request to suspend its conjunctive billing offering.

E. Large Light and Power

Large commercial and industrial customers are currently served under one main rate schedule, E-20, for customers with demands of 500 kW or more. Some components of this schedule vary according to whether the customer connects to PG&E's system at the transmission level or at the primary or secondary distribution level. In addition, many customers in this class choose to have all or a portion of their load subject to interruption by PG&E, and credits are made to customers electing this nonfirm service.

Railway customers are sometimes labeled as a separate class on revenue allocation and rate design tables. These customers are not a true customer class, however; they are served on Schedule E-20.

1. Creation of Schedule E-19

In this case PG&E proposes to divide the E-20 schedule into two schedules. The new Schedule E-19 would serve customers with maximum demands of between 500 and 1000 kW. Schedule E-20 would continue to apply to customers with more than 1000 kW of maximum demand.

No party opposes PG&E's proposal, and we will authorize the new Schedule E-19.

We suspect that rates for Schedule E-20 will typically be lower than for Schedule E-19. This rate differential could lead customers near the 1000 kW border between these schedules to increase their maximum demand to take advantage of lower rates. We do not want to stimulate this artificial increase of demand, and PG&E should incorporate appropriate restrictions in its tariffs to prevent this sort of movement from Schedule E-19 to Schedule E-20. A reasonable initial restriction is to require customers served under Schedule E-20 to take service on another schedule if maximum demand falls below 1000 kW for eight months out of twelve.

Some customers' demands vary with the season. During times of high demand, these customers have load patterns similar to those of customers on Schedule E-20, and their demand is above 1000 kW. PG&E should serve such customers under Schedule E-20 if the customer's billing history shows that the customer could annually meet the requirements for initial placement on Schedule E-20.

2. Customer Charges

The differences between DRA and PG&E discussed under customer charges for the small light and power class also apply to customer charges for Schedules E-19 and E-20. CMA agrees with PG&E's general approach and recommends maintaining consistency among the voltage levels. The parties' recommended customer charges vary somewhat according to their estimates of marginal costs and net revenue increase. The following table summarizes the parties' positions on customer charges for firm service customers. PG&E's recommendations are based on a net revenue increase of $460 million; DRA's recommendations are based on a net revenue increase of $285 million. CMA's recommendations are independent of the level of revenue change. (Exhibit 85, Table 10-1; Exhibit 176, Table 1-4; Exhibit 237-A, Table 2-4a-R.)

Table 4

Recommended Customer Charges

Schedule	Current Charges	PG&E's Proposed Charges	DRA's Proposed Charges	CMA's Proposed Charges
E-19:				
Secondary	$100	$ 225	$270	$239
Primary	$100	$ 205	$220	$220
Transmission	$100	$1100	$500	$261
E-20:				
Secondary	$100	$ 265	$370	$279
Primary	$100	$ 200	$220	$220
Transmission	$100	$1100	$500	$261

For nonfirm service options, the current customer charge is $290 for all connection levels. DRA recommends that customer charges for nonfirm customers should be higher than the recommended rate for firm service by $190 for curtailable service and $200 for interruptible service. Both CMA and PG&E set their customer charges for nonfirm service at $200 above their recommended levels for firm service. These higher charges cover the costs of the special meters needed for these services.

We have generally adopted DRA's approach to marginal costs, and we believe that DRA's recommendations for customer charges at the primary and secondary distribution level make reasonable progress toward marginal cost without undue effect on customers' overall rates.

The marginal costs underlying the PG&E's recommendation on customer charges for transmission level customers appear to include the cost of dedicated line extensions. We have earlier determined that these costs should not be included in the calculation of marginal customer cost. DRA's figures appear to be based on the revised figure, and in any event, we believe that the increase proposed by PG&E for transmission level customers is excessive for one step.

We will adopt DRA's recommendations for customer charges for Schedules E-19 and E-20, including its recommended additional increments of $190 and $200 for curtailable and interruptible service.

3. Maximum Demand Charges

DRA recommends changing maximum demand charges by 35% of the difference between current charges and full EPMC noncoincident capacity costs. CMA's recommendation is based on consistency among voltage levels. CMA proposes moving maximum demand charges 50% of the distance to marginal costs for all voltage levels, and the results of this recommendation are similar to DRA's.

PG&E recommends moving maximum demand charges for primary and secondary distribution levels by 50% of the difference between current charges and full EPMC noncoincident capacity costs. For transmission level customers, PG&E would collect in maximum demand charges the full EPMC coincident capacity cost responsibility and the portion of full customer cost responsibility not recovered through the customer charge. PG&E argues that greater progress toward EPMC-based charges is justified for these customers because low load factor customers are protected by the average rate limiter.

ACWA proposes that demand charges should move toward a marginal cost limit at the rate of 5% per year, and that these charges should distinguish between overhead and underground service (Exhibit 276, pp. 5-6).

DGS supports DRA's proposals. DGS finds that these proposals move toward an EPMC allocation while moderating rate impacts on low load factor customers.

The following table sets forth the final recommendations of the parties. Because the parties rely on different marginal costs in coming to their recommendations, the table does not accurately represent the differences in the parties' methods. ACWA's figures are its recommendations for overhead service for customers on Schedule E-20. The figures in the table represent only the approximate differences resulting from application of the parties' methods.

Table 5

Recommended Monthly Maximum Demand Charge

Voltage Level	Current Charges	PG&E's Proposed Charges	DRA's Proposed Charges	CMA's Proposed Charges	ACWA's Proposed Charges
Secondary	$3.03	$4.30	$3.30	$3.32	$2.86
Primary	$1.92	$3.30	$2.60	$2.47	$1.92
Transmission	$0.80	$0.50	$0.70	$0.49	$1.02
W/ Customer Cost		$1.30			

We are reluctant to collect the residual customer cost as part of the maximum demand charge for two reasons. First, the studies that were the basis for the customer charge for this class were sketchy and used small, diverse samples. We might be less reluctant to collect the full EPMC responsibility if we had more confidence in the accuracy of the marginal customer costs. Second, as CMA and Unocal pointed out, PG&E's proposal treats different voltage levels inconsistently.

We will follow DRA's recommended approach to maximum demand charges. DRA's approach has the virtue of treating all voltage levels consistently, and it makes substantial progress toward EPMC. In addition, DRA's recommendation appears to allow us to lower the maximum demand charge for transmission level customers.

4. <u>On-Peak Demand Charges</u>

The recommended levels of on-peak demand charges depend on the parties' positions on the ERI, their estimates of marginal coincident capacity costs, and their approach to the assignment of marginal coincident capacity costs.

PG&E recommends an ERI of 0.4 to adjust the marginal generation capacity cost. Its proposed on-peak demand charges move 25% of the difference between current charges and the marginal cost of coincident capacity. PG&E's recommended charges result in increases of 7-12%, and PG&E believes this level of increase is moderate.

DRA believes coincident demand costs should be recovered in both on-peak demand charges and on-peak energy charges. Customers may have on-peak demand that does not correspond with the instant of the system's peak. Recovering a portion of coincident demand costs in on-peak energy rates reflects lack of complete coincidence.

DRA recommends an ERI of 0.96 and moves on-peak demand charges 13% of the difference between current charges and EPMC-based coincident capacity costs.

CMA supports DRA's ERI recommendation and proposes on-peak demand charges that reflect CMA's calculations of marginal coincident demand costs. CMA approves of DRA's approach of treating all voltage levels equally, but it believes that greater movement toward marginal costs is needed. CMA recommends moving on-peak demand charges 25% of the distance to marginal costs at all voltage levels.

DGS also supports DRA's recommendations.

CLECA argues that coincident demand charges that are not recovered in demand charges should be recovered in energy charges for the corresponding TOU periods, and to this extent it agrees with DRA. CLECA opposes, however, using the ERI to adjust marginal generation capacity costs and on-peak demand charges. The rate instability that results from this adjustment gives customers a confusing and inconsistent signal. CLECA believes the on-peak demand charge should provide a long-run price signal of the cost of meeting additional on-peak demand.

FEA and Industrial Users recommend against adjusting marginal generation capacity costs by the ERI. They recommend substantial increases in on-peak demand charges. FEA notes that DRA's proposed charges move only 9% of the way toward marginal costs, and this pace would require more than eleven rate cases to reach the EPMC allocation. FEA thinks on-peak demand charges should increase roughly 50% to make reasonable progress toward marginal cost.

Both FEA and Industrial Users believe demand costs should not be recovered in energy charges, and Industrial Users offer several reasons in support of this position. Recovering demand costs in energy charges leads to lower load factors and less efficient use of the system. It also confuses price signals, and results in high load factor customers subsidizing low load factor customers. Uneconomic bypass is more likely and revenue recovery is less stable when demand costs are included in energy charges, Industrial Users contend. Under Industrial Users' proposal, 18% of the revenues from Schedule E-20 would come from on-peak demand charges. This is far short of the 39% of total costs that are caused by peak demand, but it moves at an adequate pace and in the right direction. The remaining demand costs are necessarily recovered in on-peak energy charges and other rate components.

The parties' recommended levels of on-peak demand charges for firm service customers are set forth in the following table. (On-peak demand charges for nonfirm service will be discussed separately.) The table does not account for the differences in the parties' views on the ERI or the different estimates of marginal coincident capacity cost, so the figures are not directly comparable. (Exhibit 85, Table 10-3; Exhibit 176, Table 1-4;

Exhibit 237-A, Table 2-4a-R; Exhibit 279, Schedule 8; Exhibit 266, Schedule 2.)

Table 6

Recommended Monthly On-Peak Demand Charges

Schedule	Current	PG&E	DRA	CMA	FEA	Industrial Users
Secondary	$8.95	$10.00	$10.20	$11.42	$14.97	$14.15
Primary	$8.26	$ 9.50	$ 9.50	$10.88	$13.86	$13.97
Transmission	$6.89	$ 7.40	$ 7.90	$ 8.77	$11.36	$11.48

(The recommendations of FEA and Industrial Users vary with the level of revenue increase. The figures shown on this table are the charges for a net revenue increase of $574 million.)

We have already determined that the marginal generation capacity cost should be modified by the ERI for purposes of revenue allocation. For similar reasons, on-peak demand charges should be based on ERI-adjusted marginal generation capacity costs to take into account the relation between the utility's actual reserve margin and its target reserve margin. When a utility has substantial excess capacity, the price of on-peak capacity should reflect that excess.

We will adopt the recommendations of DRA for calculating the on-peak demand charge. DRA's proposals move significantly toward EPMC without causing undue increases for any voltage level. We note that the levels of the charges recommended by PG&E and DRA are comparable. Because we believe it is important to focus on EPMC, rather than marginal cost, we choose DRA's recommended approach.

5. Average Rate Limiters

In D.86-12-091, we adopted an average rate limiter for summer rates for customers connected at the primary and secondary levels. The purpose of this limiter was to give affected customers a signal of future rate increases while avoiding severe bill impacts due to movement toward cost-based rates. The average rate limiter we adopted was set at one cent above the average summer rate for the secondary voltage level of Schedule E-20 (D.86-12-091, mimeo. p. 59).

In this case, PG&E and DRA propose to develop separate limiters for Schedules E-19 and E-20 and to increase the average rate limiter to 25% above the average summer rates at the secondary level of those schedules. This increase is premised on the perception that the Commission intended to phase out rate limiters over time. PG&E estimates that the present limiter would result in a shortfall of $23.6 million, and the recommended limiter's shortfall would be $17.2 million. The shortfall would be recovered through allocation to energy rates within each schedule.

CMA recommends that the rate limiter be set at twice the percentage increase allocated to each schedule during the revenue allocation.

CMA's recommendation is unclear, and it could lead to unintended shortfalls in revenue. We agree with PG&E and DRA that the average rate limiter should be phased out over time, and we find their recommended increase in the existing limiter to be reasonable.

Thus, the average rate limiter should apply separately to Schedules E-19 and E-20 and should be set at 25% above the average summer rate for the secondary voltage level of each schedule.

Because we intend to phase out the average rate limiter, the level of the limiter should increase over time and should never decrease, even if the average summer rate for the secondary voltage level decreases.

6. <u>On-Peak Rate Limiter</u>

The on-peak rate limiter was adopted in D.86-12-091 to mitigate the bill effects of changes in revenue allocation and rate design on extremely low load factor customers, including standby customers, who have low on-peak energy usage. PG&E agrees to use

DRA's model, which has been used in several recent proceedings to set on-peak rate limiters. The model estimates the amount of coincident capacity PG&E must have available to meet standby customers' likely loads at the time of system peak, and considers on-peak marginal energy cost to develop the on-peak rate limiters.

FEA opposes on-peak rate limiters and the use of DRA's model. FEA believes that the rate limiter does not distinguish between scheduled and unscheduled maintenance, although scheduled maintenance imposes much lower costs on the system.

FEA points out that reliable cogenerators require power only for a small number of hours a year, and the probability of such cogenerators' requiring on-peak power is very low. FEA suggests that standby customers should be charged a reservation fee rather than on-peak demand charges. This reservation fee would be equal to 2% (the outage rate of a very reliable cogenerator) of the on-peak demand charge. The monthly charge would be prorated over the days of the month when service is actually taken. Reliable cogenerators would pay this cost-based reservation fee, and unreliable cogenerators would approach the full on-peak demand charge.

DGS urges the Commission to adopt FEA's approach. DRA's method is based on capacity factor, rather than forced outage rates, and it does not adequately represent the loads of standby customers. DRA has admitted that its model is inadequate, and FEA's method overcomes many of the shortcomings of DRA's model.

PG&E and DRA respond by pointing out that the Commission rejected FEA's proposal in SDG&E's recent general rate case, on the ground that it was was inequitable and not based on costs.

We will continue the on-peak rate limiter and use of DRA's model to calculate its proper level. FEA's reservation charge appears to undercharge standby customers for the coincident demand costs they impose on the system.

7. <u>Nonfirm Service</u>

Nonfirm service allows PG&E to be able to reduce demand from certain customers at key times, particularly when high system demand or equipment failure jeopardizes PG&E's ability to meet its customers' need for electricity. The right to reduce or interrupt a customer's demand helps decrease the need for peak or emergency capacity and thus helps keep down capacity costs. In exchange for their agreement to reduce or interrupt their load at certain times, nonfirm customers pay rates that reflect credits for the benefits they confer on the system.

PG&E currently offers two basic types of nonfirm service. Curtailable service requires a customer to reduce its load to a certain level within a specified time of receiving a notice of curtailment from PG&E. Interruptible service carries all the requirements of curtailable service with an added provision that allows PG&E to interrupt service automatically. Automatic interruption is accomplished through an installed underfrequency relay (UFR) device that senses when the system's frequency declines below a certain level, a sign of a system disturbance, and automatically cuts off the load connected through the device.

For each type of nonfirm service, PG&E currently offers three options that vary in terms of the length of the minimum notice, the maximum number of curtailments or interruptions per year, and the maximum annual duration of the interruptions or curtailments.

In its application, PG&E proposed a restructuring of the nonfirm services. Customers currently on nonfirm schedules objected strenuously, leading to one of the most extensively disputed areas in this case.

Late in the proceeding, three parties representing diverse interests--PG&E, DRA, and CLECA--agreed on a proposal for resolving this issue in this case. The proposal was presented as a joint exhibit (Exhibit 88) in the update phase of the hearings.

Because the proposal was presented late in the process, other parties had only a limited opportunity to respond to the proposal. Other parties were able to cross-examine witnesses on the terms of the joint exhibit's proposals, and the ALJ allowed all parties to state their positions on the proposal in supplemental briefs.

The parties sponsoring the joint exhibit stated that if the proposal was not approved by the Commission, they would each revert to the positions they presented in the main body of hearings and argued in their primary briefs.

We will discuss briefly the parties' original positions, followed by a description of the terms of the joint exhibit, other parties' reactions to the joint exhibit, and the issues that the joint exhibit leaves unresolved. One of the significant issues not addressed in the joint exhibit is the level of the incentive for interruptible service. The parties' original positions on this issue were largely unaffected by the provisions of the joint exhibit.

a. <u>The Parties' Original Positions</u>

(1) <u>PG&E</u>

PG&E proposes to unbundle the curtailable and interruptible options and to pay separate incentives for the two different types of nonfirm service. Current tariffs allow customers to choose curtailable service without also offering to be interrupted for underfrequency events, so PG&E's recommendation is not a dramatic change from the existing tariffs. PG&E thinks its proposal clarifies the price signals connected with each type of service.

PG&E also recommends simplifying the nonfirm tariffs by narrowing the three options currently offered for each type of nonfirm service to one curtailable option with the characteristics of current Option B. Customers would still have the further choice of consenting to be interrupted for underfrequency events. PG&E's

experience has shown that there is little, if any, added value connected with the additional options.

PG&E also proposes new levels for the nonfirm incentives, reflecting the marginal costs it advocates in this case. PG&E's proposed incentives for curtailable service are derived from the marginal costs of generation, transmission, and distribution capacity. This incentive would be paid as a credit based on the level of the customer's curtailable demand, defined as the difference between a customer's average monthly peak period demand and its firm service level.

PG&E believes the credit for underfrequency interruptions should equal the value firm customers receive from avoiding underfrequency disturbances. PG&E argues that the only benefit of the UFR program is the reduced probability that firm service customers will suffer outages, and it attempts to quantify this reduced probability. PG&E proposes to base the interruptible credit on the value of the expected unserved energy (EUE) that is avoided due to the installation of UFRs. The precise determination of the expected unserved kWhs that are avoided by UFRs, however, is complicated by several considerations.

PG&E first points out that UFRs are effective only when an underfrequency event occurs that would have shed load but for the existence of the UFRs. UFRs are not effective in minor underfrequency events that trip the UFR but do not result in other load shedding. On the other hand, UFRs are also not effective in a very serious underfrequency event that results in load shedding despite the operation of the UFRs.

A good analysis of EUE is not available, so PG&E relies on an estimate with two underlying assumptions: first, that the underfrequency events in which UFRs are effective coincide with double line outages on the Pacific Intertie, and second, that each kW of interrupted load saves one kW of firm load. PG&E acknowledges that one kW interrupted by the tripping of a UFR saves more than one kW of firm load, but it believes its other assumption overstates the number of times when UFRs are effective. These distortions in its assumptions balance, PG&E argues, and lead to a reasonable estimate.

PG&E next estimates the value of unserved energy to firm service customers, based on several surveys of the costs of interruption to various customer groups. In response to criticisms from other parties, PG&E revised its initial figure to reflect inflation.

The result of PG&E's approach is a credit of $12.70/kW-year.

(2) <u>DRA</u>

DRA agrees with PG&E's proposals to separate the curtailable and interruptible incentives more clearly and to reduce the number of curtailable options.

DRA recommends offering two types of curtailable service, however. The first type, emergency curtailment, is similar to the existing curtailable option: a customer may be curtailed only when problems arise with the operation of PG&E's system. The second, new option proposed by DRA is economic curtailment. Under this option, the customer agrees to be curtailed whenever the costs of serving the customer exceed the amount recovered in rates--in other words, when shedding load is PG&E's cheapest marginal resource. These economic curtailments would be limited to 30 times per year, and the customer would be required to sign a four-year contract with four years' notice of termination. During system emergencies, reducing load is economical, so emergency curtailment would be subsumed in economic curtailable service.

DRA's calculation of incentives for curtailable service is similar to PG&E's, but the parties differ on some of the underlying assumptions. DRA argues that economic curtailment is more valuable than emergency curtailment, and it sets the level of the incentive for emergency curtailment at one-half of the incentive for economic curtailment.

Incentives should continue to be paid through reductions to on-peak demand and energy charges, according to DRA.

DRA also recommends that all nonfirm service should be provided under four-year contracts with a required four-year notice of termination.

DRA agrees with PG&E's approach to calculating the incentive for interruptible service, except for one assumption. Rather than assuming that one kW of interruptible load saves one kW of firm load, DRA believes the quantity that should be used in this calculation is the amount of firm load that would have been shed but for the presence of interruptible customers. PG&E's underfrequency load shedding schedule shows that amount to be 5% of system load. When DRA performs the calculation with its assumptions, the result is an incentive for interruptible service of $16.28/kW-year.

(3) The League

The League argues that curtailable customers offer PG&E the equivalent of additional peaking capacity, and the League's recommended incentives for curtailable service are derived from the costs of peak generation capacity and capacity-related transmission and distribution costs. The League calculates the resulting incentive to be $131.05/kW-year for the test year.

The League submits that interruptible customers supply a unique service by providing instantaneous protection against underfrequency events. Like other programs in which private parties assist PG&E in managing its loads and resources--such as generation from QFs and load management programs--the value of the interruptible programs should be measured in terms of the costs that the program allows PG&E to avoid. The League argues that having interruptible customers available when major underfrequency disturbances occur is equivalent to bringing on new generation capacity. For local underfrequency occurrences, interruptible customers are equivalent to new transmission capacity. Therefore, the interruptible incentives should reflect the cost of the avoided generating and transmission facilities.

In addition, the League believes interruptible customers can supply part of PG&E's spinning reserve requirements and thus avoid the short-term operating costs and long-term capacity costs of the resources that would otherwise supply spinning reserve. Interruptible customers also help PG&E maximize its out-of-state economy energy purchases by improving the system's reliability.

Many of these benefits cannot be quantified. The League therefore recommends that the interruptible credit should be based on avoided generating and transmission capacity costs. The League recommends interruptible incentives of $108.68/kW-year for 1990.

(4) <u>CLECA</u>

CLECA strongly objects to PG&E's and DRA's proposals to decrease the nonfirm incentives, particularly the incentive for interruptible service.

CLECA warns that DRA's approach to calculating the incentive for curtailable service, which adjusts marginal generation capacity costs by the ERI, could lead to extreme instability in these incentives, and thus in the effective rates of curtailable customers, if the ERI varies from year to year. CLECA therefore recommends no adjustment to the marginal generation costs used in calculating this incentive.

CLECA also finds fault with many aspects of PG&E's and DRA's approach to calculating the incentive for interruptible service.

First, PG&E's assumption that only a portion of underfrequency interruptions are effective was completely unsupported by any evidence, CLECA states. PG&E's witness admitted that he did not know whether firm load was saved during interruptions due to underfrequency events other than those represented by the assumed proxy of a double-line outage on the Northwest Intertie (Tr. 35:3719). CLECA argues that no basis exists for reducing the number of underfrequency events per year from the historical average of 3.44 to the 1.22 used by PG&E.

Second, CLECA questions PG&E's assumption that 30 minutes is the average duration of the outage that a firm service customer would have suffered but for the existence of interruptible customers. The record of historical interruptions is barren of information on the duration of the interruptions, and PG&E said that its estimate was based only on discussions with the engineers involved with these interruptions. CLECA submits that interruptible customers require longer to resume operations than the period when power is unavailable, and CLECA therefore estimates the duration of underfrequency outages to be one hour.

Third, CLECA takes issue with PG&E's assumption that one kW of interruptible load saves only one kW of firm load. PG&E has admitted that this assumption understates the real effect of underfrequency interruptions. CLECA finds more reasonable DRA's estimate that the next block of power shed after interruptible customers is 5% of the system's load at the substation level. Using this figure leads to an estimate that each kW of interrupted load saves 1.67 kW of firm load.

Fourth, CLECA believes that PG&E's studies understate the cost of an outage for its customers. The studies contain several assumptions--a summer outage with one hour's notice--that act to understate the actual cost of an interruption. Even correcting the lack of a conversion into 1990 dollars increases the estimated cost of an outage from $16 to $21 per kWh.

Using all of the corrections that CLECA urges results in an interruptible incentive of about $120/kW-year. Because this figure exceeds the current incentives for curtailable and interruptible customers, CLECA recommends maintaining the interruptible incentive at its current level. CLECA suggests adopting the current incentive for extended contracts, $47.68/kW-year. At a minimum, the Commission should maintain the current incentive under standard contracts of $35.76/kW-year.

(5) Industrial Users

Industrial Users fear that the reductions in incentives for nonfirm service proposed by PG&E and DRA and the resulting increases in effective rates for industrial customers will spur many of these customers to bypass the system. The sharp variations in incentives will also undermine the stability that is necessary for a customer's commitment to accept nonfirm service. This rate instability is particularly threatening when combined with DRA's proposal to lock interruptible customers into an evergreening, four-year contract.

The lack of justification of PG&E's and DRA's proposals and the substantial evidence supporting existing incentives lead Industrial Users to urge the Commission to retain the existing incentives.

(6) Anchor

Anchor thinks that incentives for curtailable service should be based on long-run marginal capacity costs, which it calculates as $99.07/kW-year for the test year. Anchor notes that this level is higher than the incentives under extended contracts (discussed below), but higher incentives are appropriate if customers may be curtailed for economic reasons, as DRA recommends.

Anchor shares CLECA's criticisms of PG&E's approach to determining interruptible incentives, and estimates that a corrected interruptible credit, based on PG&E's method, would be $91.16/kW-year.

However, Anchor believes the interruptible incentive should be determined according to avoided or marginal cost principles. Anchor points out that PG&E's tariffs state that three years' notice is required of customers switching from interruptible to firm options because "Interruptible Service is supplied from PG&E's generation reserve and transmission margin." Anchor thinks it apparent that generation and transmission costs are avoided by the presence of interruptible customers.

The studies necessary to quantify the costs avoided by interruptible customers, however, have not been performed and presented in this proceeding. Anchor therefore urges the Commission to adopt avoided costs as the proper standard for determining the interruptible incentive and to require PG&E to submit the necessary studies in its next general rate case.

In the absence of appropriate studies of avoided costs, Anchor recommends retention of the current interruptible incentive, measured by the existing differential between curtailable and interruptible rates. The resulting incentive varies by option and connection voltage level, but averages around $50/kW-year.

(7) FEA

FEA supports retaining existing nonfirm incentives. FEA points out that nonfirm customers on Schedule E-20 contribute $35 million in excess of their EPMC costs to cover the fixed costs of the system, and that this contribution would be jeopardized if nonfirm incentives were reduced dramatically. Interruptible customers make a substantial financial investment to enable them to endure interruptions, and PG&E and DRA have not taken into account these customers' investments and their consequent need for rate stability.

FEA believes the Commission should develop a method for calculating nonfirm service incentives that leads to long-term rate stability for these customers. Because the proposals presented by DRA and PG&E are not well supported and result in unstable rates, FEA believes the existing incentives for nonfirm service should be maintained.

(8) CMA

"Non-firm customers place distinctly different and lower costs on PG&E's system than firm customers," CMA states. "Service to a perfectly interruptible customer would cause PG&E to incur only marginal access costs and the marginal costs of nonfirm energy....[N]o generation capacity would need to be constructed to serve that customer. Hence, no generation capacity costs would be incurred to serve him."

CMA believes rates for nonfirm customers should ideally be set to reflect the actual marginal costs of serving such customers. The value of service approach advocated by PG&E and DRA is an unnecessary and unjustified departure from marginal cost-based rate design, CMA asserts. The result of a value-based approach is an interruptible credit that varies substantially in relation to the excess capacity of the utility. But reference to a perfectly interruptible customer demonstrates that the marginal generation capacity cost of serving such a customer is zero, no matter what the value of the interruption may be.

The record in this case lacks any analysis of the marginal costs of serving nonfirm customers, CMA states. The Commission should therefore direct PG&E to undertake such a study. Whatever rates are adopted in this case, CMA continues, completion of such a study is imperative before PG&E's next general rate case.

CMA, which represents both firm and nonfirm customers, argues that intraclass revenue allocation will be distorted until rates to nonfirm service customers are cost-based.

b. The Joint Exhibit

(1) Summary

Exhibit 88 presents the detailed proposal of the sponsoring parties. We will summarize its main provisions.

The proposal calls for two nonfirm options, as opposed to the six options for each voltage level under current tariffs. The curtailable option has the characteristics of existing curtailable option B: a maximum of 30 curtailments and 100 hours of curtailment per year, a maximum duration of six hours per curtailment, and a minimum of 30 minutes' notice. A customer may designate a portion of its load as curtailable, and the remaining load is served under firm schedules.

The interruptible option requires the customer to choose curtailable service and to install a UFR device. The load connected to the UFR is subject to an unlimited number of interruptions without warning.

The joint exhibit calls for a separate revenue allocation to nonfirm customers within Schedules E-19 and E-20 to reflect the lower expected demands of those customers. Credits paid to interruptible customers would be spread to and recovered from all customer classes.

The sponsoring parties agree to use DRA's recommended method for allocating nonfirm service revenues to Schedules E-19 and E-20. DRA's method uses actual marginal cost revenue responsibility and revenue at present rates for nonfirm service customers. DRA also includes rate discounts for nonfirm service in allocated revenue and operating revenues. As we mentioned in the section on allocated and nonallocated revenues, DRA attempts to maintain a consistent treatment for all load changes that impose the same cost on the utility, even when the source of the load changes--nonfirm service, load management, conservation, or shifting load off peak under TOU schedules--differs.

In Exhibit 89, PG&E explained how it executed the revenue allocation called for in the joint exhibit. First, revenue at marginal cost was calculated for each firm and nonfirm voltage level within Schedules E-19 and E-20. The coincident demands for nonfirm schedules were adjusted to reflect the expected demands of nonfirm customers during curtailments. Second, revenues were allocated to each firm and nonfirm voltage schedule subject to PG&E's recommended caps and floors. Any excess or shortfall in revenues resulting from the initial capping step was spread to uncapped schedules using EPMC. Third, the schedule allocations were then assigned to summer and winter seasons based on seasonal marginal cost revenues.

Under the terms of the joint exhibit, customer and maximum demand charges for the curtailable option are the same as for comparable firm service customers. Energy and on-peak demand charges are set to recover the revenue allocation to the nonfirm service schedules. (This provision of the joint exhibit appears to require some explanation. PG&E's rate tables attached to the exhibit show that the customer charge for nonfirm service is $200 higher than for firm service; DRA shows the same customer charge for all services, but adds a curtailable service charge of $190 and an interruptible service charge of $200. There is no dispute that nonfirm options require special equipment and that some charge should be imposed on nonfirm customers to recover the additional costs of this special equipment. In addition, it should be noted that PG&E eliminates the on-peak demand charge for nonfirm customers, but DRA retains it.)

Rates for service under the interruptible option are the same as under the comparable curtailable service, but interruptible customers also receive a monthly credit applied against the customer's energy bill. The credit is calculated as the value of the ability to interrupt service when underfrequency occurs, in dollars per kW-year, divided by the number of hours in a year. The resulting credit, in cents per kWh is multiplied by the customer's monthly energy consumption, and the resulting sum is credited against the monthly bill.

The joint exhibit also proposes penalties for failure to curtail demand when requested. After questions were raised about these penalties, the parties clarified the penalties in Exhibit 93. Failure to comply with a request to curtail results in a penalty equal to 80% of the annual coincident demand-related marginal capacity cost scaled by the EPMC multiplier. If the customer delays curtailing its load beyond the allotted 30 minutes' notice (or if the customer's circumstances prevent it from responding in 30 minutes), a proportion of the penalty just described will apply. The proportion is based on the length of the delay in relation to six hours, the maximum duration of a curtailment.

The joint exhibit also calls for PG&E to offer an experimental economic dispatch option. This option gives PG&E the right to curtail a customer whenever it is cheaper to curtail, rather than to serve, the customer. Customers selected for this option receive an additional credit, to be determined by PG&E at the time of each curtailment. No penalties apply to failures to curtail when requested.

The joint exhibit notes that the value of the underfrequency interruption and the level of specific rate components remain to be resolved, even if the Commission endorses the proposals of the joint exhibit.

(2) <u>Positions of Other Parties</u>

CMA offers hesitant support for the joint exhibit. CMA seems willing to accept the joint exhibit's provisions as an appropriate resolution of these issues in this case, but CMA remains convinced that its positions are correct, particularly its views on revenue allocation between firm and nonfirm customers, the notice requirement, and nonfirm rate design. CMA accordingly reserves its right to assert in future cases the principles and positions it presented in this proceeding.

Industrial Users and FEA also offer general, if qualified, support for the joint exhibit. Industrial Users have not had access to the calculations used to develop the rates in the tables attached to the joint exhibit, so their support is based only on limited information. Industrial Users find that the joint exhibit presents a logical and generally cost-based approach to nonfirm service. For similar reasons, FEA supports the cost assignment concepts shown in Exhibits 88 and 93, but for lack of information it cannot endorse any principles or practices that do not appear on the face of these exhibits.

Anchor notes that the joint exhibit was not intended as a settlement of these issues and did not follow the procedures for submitting a settlement. Anchor states that the use of EPMC-derived caps in intraclass allocation for Schedule E-20 deprives nonfirm customers of credit for the full benefits of their curtailments and interruptions. If the Commission approves the proposals of the joint exhibit, Anchor thinks it should reserve judgment on the issues covered by the joint exhibit until more complete cost studies have been performed. Anchor also objects to the joint exhibit's introducing, for the first time, a proposal to subject curtailable contracts to a three-year notice for conversion from nonfirm to firm service. Anchor believes the rate incentives established in nonfirm service contracts should continue even if the agreement is extended by failure to give notice of termination.

TURN opposes the joint exhibit. TURN believes the provisions of the joint exhibit will shift up to $25 million from the large light and power class to other customer classes. Residential ratepayers could be forced to bear responsibility for some $5 million in extra revenues because of this shift. Part of the cause of this revenue shifting is the joint exhibit's use of the EPMC multiplier to scale up marginal coincident capacity costs. This multiplication means that ratepayers are paying more for nonfirm service than the benefits they presumably receive from the curtailments and interruptions. TURN argues that if marginal coincident capacity costs, not adjusted by the EPMC multiplier, are used in calculating the discounts and credits, other ratepayers would be indifferent to the choice between interruptible customers and new sources of supply.

c. Discussion

(1) Incentive Levels

The parties to the joint exhibit have stipulated that the provisions of the joint exhibit are a "total package." After reviewing the provisions of the exhibit, we find that we cannot approve the proposal in its entirety. Nevertheless, many provisions of the joint exhibit are proposals that were independently presented and supported by individual parties, and we will approve many of the elements of the joint exhibit.

For ease in the following discussion, we should clarify at the outset that we endorse the general array of nonfirm options contained in the joint exhibit. The features of curtailable service and interruptible service are similar to those of the current tariffs, but the existing three curtailment options have been simplified into one, as PG&E proposed. The terms of that curtailable option are those of current Option B. In addition, the joint exhibit adopts a variation of DRA's proposal for an experimental economic dispatch option. This option provides for an additional credit for customers who agree to be curtailed whenever it is cheaper for PG&E to curtail, rather than serve, the customer. Under this option, curtailment for any reason is limited to 30 times annually. We will offer some refinements of this option in a later section of this decision.

The chief difficulty we have with the joint exhibit has to do with the level of the incentive for curtailable service. This issue is not addressed directly in the exhibit, but the incentive results from the guidelines for allocating revenues to nonfirm customers. These guidelines state:

"a. The coincident demands for nonfirm schedules will be adjusted to reflect the expected demands of nonfirm customers during curtailments.

"b. The marginal cost revenues for nonfirm schedules will be scaled using capped EPMC." (Exhibit 88, p. 2.)

In Exhibit 89, PG&E explains that the adjustment of coincident demand for nonfirm schedules is substantial: nonfirm customers impose only 0.06% of the system's coincident capacity costs, and nonfirm customers are accordingly assigned only that small fraction of coincident demand costs. Marginal capacity costs for nonfirm customers are also reduced in proportion to the reduction of coincident demand. Because we have determined that marginal generation capacity costs are entirely attributable to coincident demand, the marginal generation capacity cost responsibility for nonfirm customers is $0, or about $50/kW-year less than for firm customers.

Step "b" of the guidelines has the effect of amplifying this discount. Because marginal cost revenues are scaled by EPMC, the $50/kW-year differential between firm and nonfirm customers is also scaled, increasing the equivalent incentive for curtailable service by roughly one-third.

Similar effects occur for the fraction of marginal transmission and distribution capacity costs that are attributed to coincident demand.

As a result of these allocation principles, we believe the joint exhibit develops incentives for curtailable service that far exceed the costs that service allows the system to avoid.

Discarding these provisions of the joint exhibit leaves us with the need to find another approach to calculating nonfirm incentives. In the process of explaining the basis for our adopted incentives, we will also make clear why we find the joint exhibit's incentives for curtailable service to be too high.

We agree with many parties that the determination of proper incentives should focus on the costs nonfirm customers allow PG&E to avoid, and our analysis follows that general approach. CMA hypothesizes a perfectly interruptible customer, and this concept aids in our analysis. The perfectly interruptible customer's load imposes no coincident demand-related costs on the system and thus avoids all marginal generation capacity costs and a portion of marginal transmission and distribution capacity costs. If there are any constraints on the existing capacities of these systems, the customer will be interrupted, and the customer will receive service only if there is enough capacity on all systems to permit service.

The perfectly interruptible customer, then, would impose no coincident demand-related costs on the system, and the appropriate incentive would equal all marginal costs associated with coincident demand--all marginal generation capacity costs, 87.5% of marginal transmission capacity costs, and, for customers served at the distribution level, 35.43% of marginal distribution capacity costs. (We discussed these percentages in the section on revenue allocation.)

We believe these costs constitute the maximum incentive for nonfirm customers. These costs represent the value of avoiding increases to coincident demand, the primary function of the perfectly interruptible customer and certainly the focus of the current nonfirm options. If the costs of nonfirm options exceed the marginal costs of coincident demand-related capacity (as they would under the proposal of the joint exhibit), it would be cheaper for the utility to go ahead and obtain the extra capacity at the marginal cost than to pay the more costly incentives to nonfirm customers for the same amount of capacity.

There are reasons both to increase and decrease this maximum incentive. The maximum incentive could be raised because a perfectly interruptible customer might also permit PG&E to avoid other costs not strictly related to the level of coincident demand. A second reason for increasing the maximum incentive stems from interruptible customers' instantaneous reaction to system disturbances. Other sources of generation capacity--for example, the combustion turbine that is the basis for marginal generation capacity costs--lack the ability to react this quickly to the need for capacity, unless they are spinning for reserve capacity and thus incurring some additional running costs.

On the other hand, the proposed and existing nonfirm options are less valuable to the system than the hypothetical perfectly interruptible customer. To have the assumed effect of imposing no coincident demand-related costs on the system, a perfectly interruptible customer would be cut off whenever coincident demands are made on the system. A perfectly interruptible customer could be interrupted whenever generation, transmission, or distribution capacity is constrained, whenever certain types of emergencies arise, and whenever the system can benefit economically from shedding the customer's load. If the utility was short of peak capacity, for example, the perfectly interruptible customer would face frequent and lengthy interruptions during on-peak periods.

The existing and proposed nonfirm options fall short of this level of interruptibilty and therefore do not provide the corresponding value to the utility's system. A customer choosing the economic dispatch option as proposed by the joint exhibit, for example, is not automatically interruptible for economic reasons, but effectively has a choice of shedding load or not in response to PG&E's request: there are no penalties for failing to comply with PG&E's request to curtail. In addition, economic and emergency curtailments are limited in quantity and duration.

Another reason for lowering the maximum incentive is the recent experience with nonfirm incentives. In recent years, PG&E has conducted the nonfirm program in a way that resulted in few actual interruptions or curtailments. We presume that to some degree PG&E's excess capacity has reduced the need for curtailments, but the incentives have been set at levels that appear to exceed the actual benefits the nonfirm program has provided to other customers.

After taking these considerations into account, we are satisfied that the total marginal capacity costs associated with coincident demand provide a reasonable estimate of the maximum value the proposed nonfirm options offer to PG&E's system. Our incentives will be derived from this maximum value.

The next issue we face is how to divide up this maximum incentive to reflect the relative value of the various nonfirm options to the system. A customer with interruptible service who also elects the experimental economic dispatch option appears to provide the value closest to the maximum. Next in the hierarchy of value are two options: interruptible service for those customers with UFR devices (who must also agree to be curtailable), and curtailable service combined with the economic dispatch option. The nonfirm option that appears to provide the lowest relative value to the system is curtailable service, under which customers are curtailed, with notice, only when the system's conditions threaten to disrupt service to other customers.

Obviously, this hierarchy of value is imprecise. The record does not contain information on the costs avoided by these various combinations of options, and probably no good data exists for the newly proposed economic dispatch option. Our ranking arises from logic and from a recognition that one of the valuable functions of the nonfirm program is to avoid outages to firm service customers. We therefore give more weight to the emergency-related options than may perhaps be justified from an economic and historical perspective.

In dividing up the maximum incentive among these options, we find it convenient to begin with the issue of the proper level of the incentive for interruptible service to customers with UFRs.

Two features of this issue are immediately apparently and noteworthy: the intensity of the dispute and the lack of clear definition of the subject of the dispute. We suspect that these features are related.

PG&E blurs the issue by its insistent focus on the value firm customers receive from the UFR interruptions. PG&E states in its brief that avoided generation and transmission capacity costs "have no relationship to the value provided by UFRs to firm service customers." As we have discussed, we think that these avoided costs have a great deal to do with the proper level of the interruptible incentives. If PG&E's studies determined that the value to customers of avoiding interruption of firm service greatly exceeded the marginal cost of generation and transmission capacity, would we be justified in setting the incentives equal to that value? Obviously not, since it would cost less for PG&E to expand its generation and transmission capacity than to pay this value to interruptible customers. The value to customers may come into consideration if that value is less than the marginal cost for the utility to provide comparable services. But the determination of this issue must begin with a consideration of those costs.

The representatives of nonfirm customers contribute to the fuzziness in framing this issue by arguing that the interruptible customers' costs of interruption and delays in resuming operations should determine the levels of the interruptible credit. These parties have focused on costs, but on the wrong costs for this analysis. The cost to the interruptible customer is not a sound basis for setting rates in this case. We should focus on the costs the utility avoids, set the incentive accordingly, and then let the individual customer weigh its costs against the incentives in deciding whether to participate in the interruptible program. If a customer's operations are such that its costs due to interruptions exceed the incentives offered for participation in this program, the solution is not to raise the incentive to cover that customer's costs, but to provide the rate signals that make it clear that it is not economically wise for that customer to participate in the program.

Thus, we agree with CMA and Anchor that interruptible credits should be related to the costs the utility avoids by having customers available for interruption. Unfortunately, the parties have not presented a good analysis of what those costs are. When PG&E confronted this question, it offered the rather surprising answer:

> "In designing the UFR incentive level, the appropriate question to ask is 'How would PG&E have operated its system in the absence of a UFR program?' The answer to this question is that PG&E would do nothing different...UFRs are not used as a substitute for spinning reserves or other forms of capacity. Hence, UFRs result in no avoided costs for PG&E." (Exhibit 64, p. 9B-3.)

Although this passage is taken somewhat out of context, PG&E appears to be saying either that the UFR program avoids no costs and provides no value, in which case we should abandon it immediately, or that it is willing to tolerate a higher level of underfrequency events and load shedding for its system.

We disagree with either suggestion. But this answer underscores the need to develop a clear economic basis for the interruptible incentives, so that PG&E may develop a rational approach to integrating the potentially valuable resource represented by the interruptible customers into the operation of its system.

Many parties opposing PG&E's and DRA's value-based approaches recommended continuation of the existing incentives for interruptive service. The existing incentives have the virtue of being derived from marginal costs adopted in PG&E's last general rate case. The combined curtailable and interruptible incentives were based on marginal costs, allocated to the various options based partly on loss of load probability data (D.86-12-091, mimeo. pp.64-67).

Maintaining existing incentives has several problems, however. First, they are based on old marginal cost figures. Second, the 1987 general rate case set the curtailable and interruptible rate together; in this case, they are being separated more completely. Third, the existing interruptible incentives vary with the customer's choice of curtailment option, but the limitations that define the curtailment options do not apply to automatic underfrequency interruptions. Thus, the amount of the interruptible credit should not vary with the customer's choice of curtailment option.

We have earlier determined that the interruptible incentive should be a portion of the maximum incentive, but setting that fraction is extremely difficult without further and better information. Under the proposals of the joint exhibit, interruptible customers agree to "an unlimited number of sudden interruptions without warning" for all load connected to the UFR. Because interruptions occur only when the UFR trips, the customer is essentially agreeing to be interrupted during the periods when PG&E is likely to experience underfrequency events, plus the time necessary to correct or overcome the cause of the underfrequency.

We are forced to adopt a rough estimate of the value of interruptible service. Several factors enter into our adopted estimate. First, we have determined that the maximum nonfirm incentive for transmission level customers is $84.00/kW-year (the sum of the marginal generation capacity cost and the coincident demand-related portion of marginal transmission capacity costs). Second, PG&E has indicated that curtailable service has the potential to avoid all but 0.06% of coincident demand-related capacity costs under current circumstances. Third, we believe that the emergency functions of the nonfirm program are important and perhaps undervalued by the available economic approaches. And fourth, the level of this incentive should be in the proper proportion to the incentives for the other elements of the nonfirm program.

After considering these factors and the limited record on this point, we adopt the incentive initially recommended by DRA, $16.28/kW-year, as the incentive for customers with UFRs. In adopting this amount, we should make clear that we have not approved the approach DRA took in reaching this figure. Thus, although DRA later agreed that its initial figure should be escalated to reflect inflation, for our present purposes DRA's initial figure is appropriate. DRA's recommended incentive is adopted because it is the number presented in the record that best represents our balancing of the considerations we have just discussed.

Under the terms of the joint exhibit, the annual interruptible incentive is to be converted to a cents/kWh basis and paid as a credit against the interruptible customer's monthly energy use.

The question of the proper level of nonfirm service incentives should be considered again in the near future. We have already suggested some of the information and analyses that we would find helpful in resolving this issue more satisfactorily. Information on how PG&E uses interruptible customers to deal with unexpected disruptions, perhaps enhanced by computer simulations, would help in defining the specific costs that should be considered in setting interruptible credits. Information on the costs of measures like increasing spinning reserve, improving reliability measures, and purchasing emergency capacity, which may be viewed as functional alternatives to the UFR program, would also be helpful. We will direct PG&E to submit a study and proposal on nonfirm rates in connection with the workshops and hearings we direct the ALJ to arrange, and invite other interested parties to revisit this issue.

Our determination of the level of the incentive for interruptible service leaves us with $67.72/kW-year, at the transmission level, to divide between the incentives for curtailable service and for the economic dispatch option.

The evidence on this point is scanty. DRA originally proposed a similar scheme of curtailable and dispatchable service and gave these two elements equal weight (Exhibit 114, Table 3-4).

PG&E's testimony on the ability of the current curtailable options to avoid coincident demand-related costs persuades us that greater value, and a greater incentive, should be assigned to this element. We will assign 75% of the remaining amount available for nonfirm incentives to curtailable service and 25% to the experimental economic dispatch option. This ratio is based on our assessment of the relative value of these two elements and the overall proportion of the incentives for the different options.

At the transmission level, this division results in incentives of $50.79/kW-year for curtailable service and $16.93/kW-year imputed to the economic dispatch option. Since the actual incentive for the economic dispatch option is determined and paid on a case-by-case basis, this estimate is only a rough attribution of the value of this option.

Nonfirm customers connecting at the distribution level avoid additional costs associated with coincident demand, a portion of the marginal primary distribution capacity costs. These additional avoided costs raise the theoretical maximum nonfirm incentive for these customers. However, the value of interruptible service is related to system-wide disturbances, and the same incentive should apply regardless of voltage level. The increment of marginal capacity costs avoided by customers at the distribution level should result in proportional increases to the incentives for the curtailable and economic dispatch options, compared to the correponding incentives at the transmission level. Thus, after subtracting the interruptible incentive of $16.28/kW-year from the theoretical total for distribution customers of $102.77, the remaining $86.49 is allocated on a 75/25 basis to curtailable service and the economic dispatch option to develop the appropriate level of incentives for nonfirm customers connecting at either the primary or secondary distribution level.

Our adopted incentives are set forth in the following table:

Table 7

Incentives for Nonfirm Service

Nonfirm Service Option	Voltage Level Transmission	Voltage Level Distribution
Interruptible	$16.28	$16.28
Economic Dispatch (Imputed Incentive)	$16.93	$21.62
Curtailable	$50.79	$64.87

The interruptible and economic dispatch options can be combined separately or in combination with the curtailable option, so there are a total of four possible nonfirm options for each voltage level.

The incentives we adopt are based on the full marginal generation capacity costs developed in this decision. We have used unmodified marginal generation capacity costs, rather than costs reduced by application of the six-year average ERI, for two reasons. First, in D.89-12-015 in PG&E's most recent ECAC case, we adopted determinations that supported use of a one-year ERI of 1.0 as reasonable in setting capacity payments to QFs. In many ways, nonfirm customers are the demand-side equivalents of QFs who supply firm capacity, and it makes some sense to value the two resources' capacity contributions on an equivalent basis. Second, applying the six-year ERI used for purposes of revenue allocation and rate design would dramatically reduce the incentives for nonfirm customers. We are reluctant to take this step without a more careful consideration of this issue.

The adopted incentives, combined with the phase-in we adopt later in this decision, should result in little disruption to existing nonfirm customers. Compared to the incentives of standard contracts, which will apply to all existing nonfirm customers by the end of 1989, the incentive for curtailable service is higher than existing incentives, which is appropriate in light of this option's overwhelming ability to avoid coincident demand-related costs. The adopted incentives for interruptible service are lower than existing incentives, but the higher incentives for curtailable service help offset this decrease, because all interruptible customers are also curtailable. The largest effect is on existing customers choosing Option C, which provides for curtailments on 10 minutes' notice. Some of these customers will find the economic dispatch option attractive, and the benefits of this option should reduce the effects of somewhat lower incentives for interruptible service.

(2) Other Aspects of the Joint Exhibit

Most of the remaining elements of the joint exhibit are based on recommendations raised during the hearings in this case. We approve these remaining elements, although several provisions require modification or clarification.

First, our rejection of the implied incentive for curtailable service requires a modification to the proposed revenue allocation for nonfirm customers. The necessary modification can be accomplished by negating point 2 (a) on p. 2 of Exhibit 88, which we previously quoted. If coincident demands for nonfirm schedules are not adjusted to reflect the expected demands of nonfirm customers during curtailments, then a greater revenue responsibility arises for nonfirm customers, and the high implied incentive for curtailable service is removed. We will substitute the express incentive we have adopted in place of the implied incentive. As we discussed in connection with the distinction between allocated and nonallocated revenues, nonfirm customers' capacity savings are credited against their rates, and the cost of the nonfirm discounts are spread to all customers.

Second, the penalty for each failure to curtail, as defined in Section 7 of the joint exhibit, should be 80% of the incentives we have adopted. The joint exhibit's penalty was geared to the implied curtailable incentive.

Third, PG&E and DRA still differ on how to spread the curtailable credit to rate components. PG&E proposes to apply the credit first to reduce the on-peak demand charge and to use the remaining amount to reduce energy charges. DRA argues for retaining the current method of spreading the curtailable credit, which is to spread the credit in a way that maintains the relative price signals expressed through demand charges and energy rates. DRA advocates spreading the credit according to the proportion of coincident demand-related costs collected in each rate component.

We agree with DRA that PG&E's proposed method of spreading credits could give an inappropriate signal to nonfirm customers to increase on-peak consumption. We adopt DRA's approach to this issue.

Finally, the economic dispatch option has some confusing elements. The joint exhibit defines this as an additional option for curtailable customers, but there appears to be no reason that interruptible customers could not also take advantage of this option. If an interruptible customer also elects to be dispatchable on economic grounds, it should be understood that the 30-curtailment limitation does not apply to automatic interruptions for underfrequency events.

We have several concerns about the ability of the economic dispatch option to operate effectively and to take full advantage of the resource represented by these dispatchable customers. However, we will permit PG&E a chance to develop this experimental option. PG&E agrees in the joint exhibit to "report annually on the results of implementing and operating the economic dispatch option" and to submit the option to annual review. This report and review should take place in connection with the reasonableness phase of the ECAC proceeding.

d. Other Issues

(1) Phase-In

In its original proposal on nonfirm service, PG&E recommended phasing in its new incentives over time to avoid disproportionate effective rate increases to existing interruptible customers (Exhibit 40). Many other parties supported a similar phase-in if the Commission adopted PG&E's or DRA's proposed interruptible incentives.

We have not adopted the incentives proposed by PG&E or DRA. However, our adopted nonfirm incentives will result in effective rate increases for some customers, particularly those who were served under the extended contracts. To limit the effect of our adopted incentives on nonfirm customers, we will adopt PG&E's phase-in, which essentially limits rate increases to 10% per year.

(2) Customer Charges for Nonfirm Service

As we mentioned in our discussion of customer charges, we endorse DRA's added monthly charges of $190 and $200 for curtailable and interruptible service. The customer charges for nonfirm service in current tariffs reflect these added charges, and no party presented a reason to change the current tariffs.

(3) Extended Contracts

In D.86-12-091, we allowed nonfirm contracts entered into before December 22, 1986, to retain the incentives in effect on that date, even though contracts signed after that date would have somewhat lower incentives. Anchor proposes that its extended contracts should be renewed for another three years, because of the financial and contractual obligations it has assumed to be able to take firm service.

PG&E proposes to allow the contracts extended by D.86-12-091 to expire at their end of their current term. All such contracts will expire before the end of this year.

We agree with PG&E that these contracts should not be extended any further. Our previous decision allowed the customers to receive service under the terms stated in the original agreement, even though the incentives under those contracts were higher than those found reasonable in D.86-12-091. Customers with extended contracts had no reasonable basis for expecting those incentives to continue beyond the terms of the contracts, and other ratepayers would be harmed by continuing the old incentives.

(4) Telephone Line Requirements

PG&E proposes to require nonfirm customers to make available a telephone line and space for a notification printer. Simultaneous telephone and printed notification of curtailments has improved the effectiveness, speed, and accuracy of its notifications. The improved ability to curtail on short notice increases the value of curtailable load, according to PG&E.

PG&E's proposal was not opposed by any party, and we will adopt it.

(5) UFR Setting

UFRs are currently set to trip when frequency drops below 59.75 Hertz. Anchor argues that the standard used to describe an effective UFR interruption in PG&E's calculation of the interruptible incentive, a double line outage on the Pacific

Intertie, leads to the conclusion that UFRs are not effective and not needed to avoid outages until frequency drops below 59.6 Hertz. Anchor recommends lowering the settings for UFRs to 59.7 Hertz.

PG&E opposes Anchor's suggestion. PG&E believes the isolated facts presented by Anchor do not support a conclusion that the existing standard should be lowered, nor has Anchor presented any analysis of those facts to back up its suggestion.

We are not persuaded by the information presented by Anchor that changing the setting of the UFRs is desirable or justified, and we will not direct PG&E to change the present settings.

e. Conclusion

We have discussed at considerable length the issues raised by the nonfirm options. It should be clear from this discussion that we have many concerns about the functions, costs, and benefits of the nonfirm service options. We conclude that the program needs improvement in several respects, and we offer the following suggestions for the consideration of the parties.

1. The function of this program in PG&E's system needs to be clearly defined. Nonfirm options have a potential to give PG&E great flexibility in maintaining firm service during times of high demand or unexpected disruptions. It is not clear that PG&E has a systematic approach to determining when to interrupt or curtail customers. This lack of definition raises the concern that other customers may be paying, through incentives for customers with nonfirm service, for services that they are not receiving. For their part, customers with nonfirm service need a clearer idea of the circumstances when they may be curtailed, so that they can make rational decisions about whether to participate in the program.

2. There should be a logical, economic basis for the incentives. With a better definition of the function of this program, we should make better progress in defining the costs and benefits of this program to PG&E's system.

3. Although we have approved the joint exhibit's provision for roughly annual changes in nonfirm incentives, we believe that the method for calculating these incentives should have a fairly stable basis. In keeping with our desire to develop a sounder economic basis for the nonfirm service options, we believe that we should have sufficient stability in the incentives to allow the customers considering the nonfirm service options to make informed and intelligent business decisions.

4. The simplification proposed by PG&E and adopted in the joint exhibit is appropriate for now. With more clarity in the function and basis for nonfirm service, however, it may eventually be worthwhile to develop other options for nonfirm service or modifications like the changes to eligibility requirements proposed by the League that will benefit both participating and nonparticipating customers.

Because the information and analysis needed to derive more accurate nonfirm incentives were not presented on the record in this proceeding, we will keep this issue open for reconsideration. The first step in this reconsideration is to collect the information on the various costs that are relevant to nonfirm incentives. We will instruct the ALJ to set up a workshop, chaired by a representative from CACD, to determine what data is needed to resolve this issue. The ALJ should arrange for additional informal meetings or formal hearings, as necessary, to achieve the goal of refining the nonfirm incentives.

8. Schedules E-24 and E-25

Schedules E-24 and E-25 attempt to create TOU options to suit the needs of nonagricultural water pumping accounts. Schedule E-24 has an on-peak period for only three weekdays, instead of five, and Schedule E-25 has a four-hour, rather than a six-hour, peak period. Customers on these schedules are assigned staggered peak days or hours to control the overall coincident demand for these schedules.

ACWA points out that these schedules have not been successful. No customers have signed up for service under Schedule E-24, and only one customer receives service under Schedule E-25. ACWA believes this lack of response is due to water pumpers' inability to interrupt their operations for more than three hours. ACWA offers several suggestions to remedy the defects of these schedules.

First, ACWA proposes to eliminate Schedule E-24. PG&E agrees, and so do we. Schedule E-24 will be eliminated.

Second, ACWA proposes to reduce the on-peak period under Schedule E-25 from four hours to three hours. At the same time, ACWA recommends increasing the on-peak energy charges and opening the schedule to all customers eligible for Schedules E-19 and E-20, subject to a limit of 500 customers.

DRA suggests an option within Schedule E-25 to incorporate several modifications to ACWA's proposal. DRA would require the customers under this schedule to agree to curtailable service. The customers would be subject to not more than two curtailments for the entire six-hour peak period each year, and curtailments of this length would require six hours' notice. Two- to three-hour curtailments would not be limited in number, but would require one hour's notice. The incentive would be 72.5% of the incentive for curtailable service under Schedules E-19 and E-20. DRA also recommends restricting the schedule to water districts or agricultural customers who offer 500 kW or more of curtailable load. With these modifications, DRA supports an experimental option for water pumping customers.

PG&E concurs with DRA's suggestions and suggests elimination of the existing four-hour peak option of Schedule E-25.

We will adopt DRA's proposal for a new option. To avoid confusion, PG&E should establish this option as a separate tariff schedule, designated Schedule E-26.

9. Schedule E-11

ACWA also proposes an experimental option based on Schedule A-11. The proposed Schedule E-11 would have an on-peak period of three hours, rather than six, and the on-peak energy rate would be increased. The tariff would be limited to 500 customers, and the notice provisions described for Schedule E-26 would apply.

PG&E conditions its support for the proposed Schedule E-11. PG&E believes customers selecting this schedule should meet the requirements for participation in the small commercial interruptible program. The option should be limited to water districts.

DRA thinks the on-peak period should be at least four hours long unless service is nonfirm.

We will authorize an experimental Schedule E-11, based on ACWA's proposal as modified by PG&E. However, to avoid conflict with the terms of the small commercial interruptible program, at least six hours' notice will be required for six-hour curtailments. PG&E may want to follow DRA's suggestion to use a different designation for this schedule, to avoid confusion with Schedule A-11.

10. Schedule A-RTP

Schedule A-RTP is a real time pricing option for large industrial customers. The schedule has been experimental, and PG&E has had reasonable success in attaining the goal of calculating hourly prices and communicating them to customers on this schedule.

DRA and PG&E agree on most of the elements of this schedule.

PG&E recommends differentiating the customer charge for Schedule A-RTP by the corresponding schedule and voltage level. DRA agrees to differentiation by voltage level, but would apply the customer charges for Schedule E-20 to all customers, in the interest of minimizing the changes to existing rate design.

We conclude that customer charges for Schedule A-RTP should be the corresponding charges of Schedules E-19 and E-20, differentiated by both voltage level and the size of the customer's load.

DRA and PG&E agree that maximum demand charges should be differentiated by voltage level. PG&E agrees with DRA's proposals for setting Schedule A-RTP's incremental cost multipliers. We will endorse and adopt the agreements of the parties on these issues.

DRA also asks PG&E to work with DRA in reviewing the initial results of this experimental rate, before expanding the program in 1991. We agree with DRA's suggestion. PG&E should also consider proposing real time pricing options for other customer classes in its next general rate case, as DRA recommends.

11. Standby Service

Standby service is provided under Schedule S to customers, typically cogenerators, who normally supply part or all of their loads from private facilities. Schedule S requires standby customers to enter into an evergreening one-year contract for standby service. These customers receive service from the utility only sporadically, usually during repairs or maintenance of the private generators. The standby customer's unusual pattern of demand on the utility's system complicates setting rates based on the utility's cost of providing service to standby customers.

a. Capacity Charge

All parties agree that the capacity charge for standby service should be set at the level of the maximum demand charges for Schedules E-19 and E-20. We will adopt this recommendation.

b. Billing Adjustment Factor

In D.86-12-091, we adopted a billing adjustment factor of 85% for standby customers. Monthly standby charges are assessed against 85% of the customer's capacity as stated in its standby contract. The 85% figure was derived from the ratio of average to maximum demand for regular service customers with loads comparable to standby customers' loads. Because ordinary customers do not impose demands on the system equal to their highest annual demand in every month, we determined that it would be unfair to base charges to standby customers on their full contract demand.

PG&E argues for the elimination of this adjustment. PG&E asserts that no reasonable cost basis supports this adjustment, and that standby customers should be billed at the full level of their contract capacity. PG&E points out that the maximum demand charge for regular service customers may not cover their full noncoincident demand cost responsibilities. The costs not covered by the maximum demand charge are recovered in energy charges. Because standby customers purchase less energy than regular service customers, standby customers do not make a proportionate contribution toward noncoincident capacity costs. Eliminating this adjustment will assure that standby customers bear more of their rightful responsibility for noncoincident capacity costs, according to PG&E.

DRA opposes PG&E's position. It argues that standby customers use some energy, and thus make a contribution toward noncoincident capacity costs. Elimination of the 85% billing adjustment factor would inequitably assign disproportionate costs to standby customers.

FEA states that if the billing adjustment is removed, standby customers will be assessed a demand charge on a 100% ratcheted basis, but regular service customers would pay based on their actual demand without any ratchet or carryover. FEA believes that standby customers will be overcharged if the adjustment is eliminated.

Unocal contends that the circumstances that led the Commission to adopt the billing adjustment have not changed. The adjustment was adopted to account for standby customers' irregular consumption patterns, and many customers do not use energy during some billing periods. Standby customers have little energy use relative to the demands they place on the system, and when they do place demand on the system it is typically only for the duration of an outage of their own equipment. None of these characteristics has changed in the past three years, Unocal argues, and the billing adjustment should be retained.

For the reasons already stated, DGS joins the opponents of PG&E's proposal.

We agree that the 85% billing adjustment factor should continue for this rate case cycle. We are somewhat disturbed, however, by the lack of solid data on the demand characteristics of standby customers that would illuminate the parties' contentions on this issue. Better information would help set the charges for standby customers more precisely.

c. Average Rate Limiter

SCC proposes to extend the protections of the average rate limiter to standby customers. The present average rate limiter applies to all customers on Schedules E-19 and E-20 except those taking standby service. SCC argues that no factual or policy basis exists for this exception, and the lack of a rate limiter has a particularly detrimental effect on small cogenerators.

DRA, PG&E, and DGS support extending the average rate limiter to standby customers, provided that it applies to all of the customer's load.

We agree that the average rate limiter should apply to all of a standby customer's regular service load, in the same way that it applies to other customers on Schedules E-19 and E-20. The maximum demand used to determine the regular service charge for any month will be reduced by the customer's demand in that month. The standby contract capacity charge should not be subject to the average rate limiter.

d. Selecting the Level of Contract Capacity

PG&E and DRA suggest that the level of capacity specified in the standby contract should be the product of negotiations between the utility and the standby customer. The contract capacity level should correspond to the customer's expected standby demand. PG&E and DRA believe that leaving this decision with the customer, as currently allowed, will lead to the selection of inappropriate capacity levels by customers seeking to avoid certain demand charges.

CMA supports the existing provisions, which permit the customer to specify the level of capacity in the contract. No evidence has been presented that the abuses feared by PG&E and DRA have actually occurred, CMA argues. Giving the utility what amounts to veto power over the customer's decision could also lead to abuses, such as the utility's insistence on setting the contract capacity at the customer's full demand requirements, even though the customer may prefer to drop a portion of its load when its primary power source is unavailable. Requiring negotiations between the utility and the customer is an unreasonable interference with the customer's management of its loads and resources, in CMA's view.

We will continue to allow standby customers to specify the level of capacity in their standby contracts. No evidence was presented to justify changing the existing provisions, and we prefer not to limit these customers' business decisions. If the abuses mentioned by PG&E and DRA pose a problem, then perhaps the consequences of underestimating the contract capacity should be more severe.

e. <u>Waiver of the Standby Charge</u>

Schedule S allows for a reduction of standby charges when the customer can demonstrate from log sheets that the customer's generation unit was out of service at the time of the customer's maximum demand. In these circumstances, the customer's maximum demand charge will cover the utility's cost of providing capacity for this portion of the customer's load, and separate recovery through the standby charge is unnecessary.

SCC argues that this existing waiver provision is unfair to small cogenerators. Most cogeneration units of less than 1000 kW are automated, and the records required under the tariff are not available. Because these units are out of operation at times during the month, they do not effectively reduce the customer's maximum demand. Standby customers with these small units end up paying both standby charges and demand charges for the same load. SCC therefore urges the Commission to exempt standby customers with cogeneration units of less than 1000 kW from the documentation requirement. Under SCC's proposal, these customers would be exempt from standby charges unless PG&E could demonstrate that the customer's demand was reduced due to operation of the cogeneration unit.

PG&E opposes SCC's suggestion. SCC has presented no evidence that the outages it asserts are typical of small cogeneration units coincide with the customer's maximum demand. Unless such a coincidence can be demonstrated, there is no basis for the assumption that underlies SCC's proposal. Putting the burden of proof on PG&E creates enormous expenses for special metering and extra PG&E employees, an expense that SCC's witness believes PG&E and its ratepayers should bear. The proposal also discriminates against cogenerators of greater than 1000 kW, according to PG&E.

We will not adopt SCC's proposal. SCC has not presented compelling evidence to support a crucial assumption, that the outages of small cogeneration units would coincide with the customer's time of maximum demand. In addition, it appears that it would be less expensive for small cogenerators to develop a system of automated record keeping to meet the requirements of the tariff than for PG&E and its ratepayers to incur the expenses associated with implementing SCC's proposal.

f. Special Facilities Payments

Customers who operate their own generators in parallel with PG&E's system are required by Rule 21 to be responsible for the costs of interconnection facilities. The customers may either install, own, and maintain the facilities directly, or they may pay PG&E to supply these services.

Customers' interconnection facilities may also be adequate to supply the customers with standby power. Unocal argues that such customers are essentially paying twice for the same facilities: once through either the direct costs of ownership and maintenance or through payments to PG&E under Rule 21, and a second time through standby contract capacity charges. Unocal recommended that separate customer and transmission contract capacity charges should be developed for standby customers who make special facilities payments under Rule 21.

PG&E revised its proposal to take Unocal's points into account (Exhibits 51, 91). It now proposes to lower the customer charge and standby contract capacity charges for standby customers who own or pay special facilities charges for all of the customer access facilities need to allow PG&E to deliver power to the customer. PG&E later amended its proposal to allow lower rates for customers who own or pay for the most expensive types of equipment. Unocal and CMA support PG&E's revised proposal.

PG&E had proposed that EPMC-based customer costs that are not recovered in the transmission customer charge should be recovered in the maximum demand charge. For standby customers, the maximum demand charge is also the standby charge. PG&E therefore proposes to remove the customer cost component from the transmission maximum demand/standby charge for customers qualifying for the lower charges.

For customers qualifying for the lower charges, the customer charge would recover only EMPC-based billing costs and the contract capacity charge would cover only noncoincident capacity costs. Customers not qualifying for the lower charges would pay the regular customer charge and standby contract capacity charges.

CSB objects that under PG&E's proposal QFs who pay most, but not all, of the cost of special facilities will not be eligible for the lower charges. CSB proposes that either PG&E should negotiate with the individual transmission level customers to arrive at appropriate charges to eliminate double charging, or that these customers should be allowed to purchase the remainder of their customer access facilities and thus to qualify for the lower rate.

PG&E believes that its approach is fair and that its method of determining which customers qualify for lower charges is logical and practical. Individual negotiations on lower charges would be expensive and time-consuming.

We agree that customers should not be charged twice for the same services or facilities. Unocal has pointed out an inadvertent duplication of charges, and PG&E has responded with a reasonable and workable solution. We also agree that negotiating lower charges with each of its standby customers would be inefficient. However, in the interest of avoiding double charges, we think that customers who are responsible for most, but not all, of their special facilities costs should have the option of assuming full responsibility for those facilities, thus qualifying for the lower charges. With that modification, we will adopt PG&E's proposals.

g. Reduced On-Peak Demand Charges for Scheduled Maintenance

Because scheduled maintenance of a standby customer's alternative generation unit can be arranged to avoid any operational problems for the utility, FEA proposes that on-peak demand charges should be reduced for on-peak consumption associated with scheduled maintenance.

PG&E thinks this proposal is unnecessary. Customers can schedule maintenance of their alternative generation units outside of the peak periods and avoid associated on-peak charges altogether. Even if maintenance is scheduled for the on-peak period, the on-peak rate limiter provides the same protection that is available to regular service customers.

We agree with PG&E that FEA's proposal is unnecessary.

h. Differentiation of Standby Services

DRA recommends that in future general rate cases, PG&E should differentiate between backup, maintenance, and supplemental service for all standby customers. FEA and DGS support this recommendation. DGS believes that PURPA requires different charges for the different types of standby service, and that differentiation is needed to develop the appropriate cost-based charges.

PG&E acknowledges the desirability of distinguishing between supplemental use, on the one hand, and maintenance and backup power, on the other. However, the only way to distinguish between these types of service is by metering generator output. This type of metering raises questions of responsibility for meter costs, physical constraints on installation, and access to the customer's facilities by PG&E personnel. These issues have not been explored in this proceeding, and PG&E therefore opposes DRA's recommendation.

DRA suggests further that the Commission should require PG&E to provide a study of the cost of metering and collecting data needed to distinguish between the different types of standby service as part of the next general rate case.

We agree with PG&E that this issue has not been explored adequately in this case. We will follow DRA's suggestion and require PG&E as part of its next general rate case to submit a study of the costs of metering and obtaining the data needed to distinguish between the different types of service.

i. Unconventional Technology Allowance

Schedule S currently provides for up to 300 kW of free contract capacity for customers with alternative generators powered by sources other than fossil fuels. PG&E and DRA recommend termination of this experimental allowance, because customers should be charged on the basis of costs, whatever the technology of their generators may be. The tariff provides continuation of the allowance for 60 months after customers receive notice of the termination. No party opposes this suggestion.

We agree that this exemption should be eliminated.

12. Economic Development Rates

PG&E proposes two experimental schedules, Schedules ED-19 and ED-20, for customers in special enterprise zohes established by the State of California. The enterprise zones are economically distressed areas that have been singled out for special incentives to stimulate job development and economic growth. PG&E believes its proposed rates complement the State's efforts.

The schedules would offer a three-year declining discount to no more than twelve customers in enterprise zones who add at least 500 kW of new load. The rate would be set to ensure that the average rate under these schedules would equal or exceed PG&E's marginal cost of service.

DRA opposes the special schedules because it believes discounts of the sort contemplated by the economic development rates may be offered in special contracts reviewed in the expedited application docket (EAD). The EAD has the advantage of allowing case-by-case review of these agreements. In addition, PG&E may find it effective to offer conservation incentives as an alternative to rate discounts, and the EAD can accommodate this alternative. Because other ratepayers will make up for the discounts offered under PG&E's proposal, DRA feels the review incorporated into the EAD is necessary.

If the Commission accepts PG&E's proposal, DRA suggests several safeguards. First, the schedules and the discounts should not extend into any year when PG&E projects, based on the determinations of this decision, that it will need new capacity. Second, the experimental schedules should be limited to eight customers, rather than the twelve PG&E proposes. Third, the discounts should not be available for load that merely relocates from the service territory of another California utility.

PG&E states that customers interested in these economic development rates have expressed a concern about the uncertainty associated with the EAD. PG&E finds DRA's additional safeguards to be acceptable if the experiment is approved.

Although PG&E proposed two separate schedules, we think it will be administratively simpler to authorize a single experimental Schedule ED, based on PG&E's proposal. However, we will add two of the three limitations DRA recommended to protect the interests of other ratepayers. We will not adopt DRA's limitation to years in which PG&E does not need new capacity. Although we have used this protection in approving special sales contracts, the standards for economic development rates are different from those for uneconomic bypass. As well, the DRA limitation is unnecessary during the current rate case cycle, when PG&E will not need new capacity.

In addition, we will instruct PG&E to take advantage of the opportunity presented by this experiment to ensure that these new customers are informed of cost-effective conservation and load management measures they may take to reduce their electric bills and the load they place on the system. We encourage other California utilities to investigate economic development rates for any special enterprise zones in their service territories.

F. Agricultural Class

1. Introduction

Agricultural schedules have been extensively revised in recent years (see D.87-04-028). To help agricultural customers lower their bills and to reduce the marginal costs and associated revenue responsibility for the agricultural class, we have adopted several TOU schedules, and larger agricultural customers are required to take service under TOU schedules when TOU meters are available. Schedule AG-1 is the schedule for basic general service. Schedule AG-4 and AG-5 are the basic TOU schedules; Schedule AG-5 is designed for larger customers. Schedule AG-6 is an interim schedule that will be unnecessary when enough TOU meters are available and customers are converted to Schedule AG-5. Schedule AG-R is a split-week TOU schedule, which allows for daytime irrigation pumping for part of the week. Schedule AG-V is a short-peak TOU schedule that applies on-peak rates to a four-hour, rather than a six-hour, period. The agricultural schedules are subdivided into two or three categories--A, B, and C--depending on the level of demand.

The agricultural class is farther away from EPMC, as calculated from current marginal costs, than any other customer class. If we continue our intended progress toward a revenue allocation based on EPMC, the agricultural class as a whole would face rate increases of 40-50%.

In response to this large potential increase, DRA states that its policy is to move as much as possible toward cost-based rates, so that agricultural customers will be informed of the costs of the various service options that PG&E offers. If agricultural customers can minimize their use of services that impose high costs on the system, then the overall cost of service to the agricultural class will decline. As a result, the EPMC-based allocation will decline, and large increases can be avoided.

DRA offers an illustration of how this process will work. Many single agricultural customers have multiple accounts. In some cases, the multiple accounts are due to a geographical separation of fields, but in at least some cases, separate accounts, requiring separate secondary distribution line transformers, service drops, meters, and bills, are in close proximity. A consolidation of such accounts would both lower the charges to the customer and decrease the cost of service, and eventually the revenue allocation, to the class.

Although PG&E does not express its overall policy toward agricultural rate design in the same terms as DRA, its shares many of DRA's specific recommendations.

As a general matter, we agree with DRA that the components of agricultural rate design should reflect their costs. In the past, we have attempted to avoid disruptive rate increases to agricultural customers, and we have taken such steps as capping the revenue allocation to the class and introducing many service options to reduce customers' bills. Cost-based rates are another way to reduce to the cost of service to the class and avoid allocation-based increases by lowering the revenue allocation to the class.

We have already taken several steps to lessen unduly harsh rate impacts on agricultural customers. We have capped the interclass allocation and adopted an approach to the intraclass allocation that lessens the effect on other agricultural customers of our desire to keep Schedule AG-5 competitive with alternative pumping fuels.

Given the intricacies of balancing our goals of reaching EPMC with the need to ensure that California's farmers can buy electricity at affordable rates, we believe some further examination of rates within the agricultural class is needed. In the short term, we would like to take a closer look at the impact the rate schedules we are adopting will have on customers served under Schedule AG-5. We specifically want to examine whether the rates that result from this decision are in fact competitive with alternate pumping fuels for these customers. To accomplish this, we will hold the record open in this proceeding to take testimony on that specific issue early in 1990. We will leave the scheduling to the ALJ, but the matter must be decided before May 1, 1990, to permit any rate changes to take effect before summer rates begin.

Taking a somewhat longer view, we also want a broader study of agricultural rates to be completed before the end of next year, so that we will have more detailed information before us in PG&E's rate design window proceeding, anticipated in late 1990 or early 1991. We will direct PG&E and CACD to conduct a joint study of the agricultural class' marginal costs and intraclass allocation and their implications for rate design. This study should be completed by November 5, 1990, and served on the Commissioners, DRA, CFBF, PUPC, the assigned ALJs, and any other party requesting a copy.

2. <u>Customer Charge</u>

Both DRA and PG&E recommend a $10 monthly customer charge for agricultural accounts. We will adopt the parties' recommendation.

3. <u>Maximum Demand Charges</u>

Both PG&E and DRA agree that the increase to maximum demand charges to Schedules AG-1, AG-R, AG-V, and AG-4 should be capped consistently with the overall percentage cap used in intraclass rate design. The parties differ, however, in the specific calculation of the cap.

PG&E sets the cap at the sum of the interclass and intraclass caps for the agricultural class. PG&E believes that its recommendations result in moderate increases that permit sufficient movement toward EPMC, especially in light of the substantial increases in demand charges that resulted from the reorganization of agricultural schedules in 1987-88.

DRA caps the increases to these schedules at five percent over the total cap on intraclass and interclass agricultural revenue allocation. DRA believes that a more aggressive movement to EPMC is warranted because the maximum demand charges for these schedules remain considerably below their EPMC levels. Although the resulting percentage change may seem large, the bill impact of its recommendation is still within DRA's goal of limiting the effects on individual customers' bills.

We agree with DRA that a more rapid movement toward EPMC is justified for this rate component. Maximum demand charges have a great potential for conveying to a customer the true cost of an expensive component of the system's costs, and even with the increases proposed in this case, the rates will remain substantially below EPMC levels. Although the percentage increase is comparatively large, the bill effect is moderate. We will adopt a cap for the maximum demand charges of Schedules AG-1, AG-R, AG-V, and AG-4, set at the level of 5% above the sum of the interclass and intraclass percentage caps.

For Schedules AG-5B and AG-5C, DRA calculates that the maximum demand charges currently exceed an EPMC-based allocation of noncoincident capacity costs plus customer costs. For the level of increases in revenue requirement requested by PG&E, DRA recommends no change in these charges. At lower levels of increases, the combination of time-differentiated rate components would not recover marginal costs. DRA recommends setting the time-differentiated components at marginal cost, and decreasing the maximum demand charge on a residual basis. The maximum demand charge for Schedule AG-5A, which is not differentiated by seasons, would then be set to produce the same revenue for the same consumption that the seasonally differentiated maximum demand charges of Schedule AG-5B and AG-5C would produce.

In its opening brief, PG&E agrees with DRA's approach.

In its comments on the proposed decision, PG&E argues that DRA's approach should be limited so that the maximum demand charges for Schedule AG-5 do not decrease below current levels. DRA acknowledges that its approach leads to unexpected decreases and recommends that decreases be limited to EPMC levels.

We will adopt DRA's recommendations for determining maximum demand charges for Schedules AG-5A, AG-5B, and AG-5C, subject to PG&E's suggested floor of the current charges.

4. <u>On-Peak Demand Charges</u>

PG&E sets on-peak demand charges for agricultural TOU schedules subject to the same cap it recommends for maximum demand charges.

DRA thinks that on-peak demand charges can be set at EPMC levels without undue effects on bills. DRA calculates the EMPC level for on-peak demand charges by correlating on-peak energy use and on-peak demand with coincident demand. Since it is possible to move to EPMC levels without adverse effects on customers' bills, DRA believes the Commission should do so. This step would lead to better communication of costs to customers. PG&E's proposal to achieve EPMC levels in a series of steps would leave customers guessing about the ultimate level of these charges.

We agree with DRA that communicating the cost and level of on-peak demand to customers is important. DRA's overall scheme offers customers on TOU schedules a chance to benefit directly by shifting load away from peak hours. DRA's proposal creates appropriate incentives for shifting consumption, and for this rate component achieves our goal of EPMC-based rates. We will adopt DRA's recommendation for setting on-peak demand charges.

5. <u>Demand Charge Limiters</u>

Rate limiters of various types were developed in D.86-12-091 to mitigate large bill impacts to customers in the large light and power class. The demand charge limiter was extended to the agricultural class in D.87-04-028. Demand charge limiters currently apply only to the "B" and "C" series of schedules, for customers with connected loads of 35 horsepower or more. Three issues arose concerning the application of demand charge limiters to the agricultural class.

a. <u>Interpretation of the Tariff Provisions</u>

CFBF contends that PG&E misapplies the demand charge limiter to the detriment of certain agricultural customers. The tariff states that a demand charge limiter applies in any billing month when:

a. seasonal billing demand for the previous month of the same season was zero; and

b. energy use in kWh divided by recorded maximum demand (in kW) in the same billing month is less than or equal to three.

CFBF contends that PG&E is not applying the demand charge limiter as required by the tariff language and intended by the Commission. For example, if a customer had no billing demand in November and no billing demand in December, CFBF believes that the demand charge limiter should apply. PG&E does not apply the limiter in these circumstances.

PG&E responds by pointing out that the tariff applies the demand charge limiter only when the "seasonal billing demand" for the previous month is zero. CFBF interprets this term to refer to the billing demand for the previous month, but the tariff defines "seasonal billing demand" in terms of the highest billing demand charge recorded in the months of the same season during the previous twelve months. PG&E believes that its interpretation is based on the tariffs and consistent with the Commission's intent--to allow agricultural customers to test their pumps during the off-season.

We concur with PG&E's interpretation. The demand charge limiter is designed to allow minimal energy use during a particular season. If the customer is recording more than the allowed minimal use, then that customer is not truly a seasonal customer of the sort that the demand charge limiter is designed to protect. We adopted this limiter for agricultural schedules "to avoid severe bill impacts in months when customers only perform maintenance" (D.87-04-028, mimeo. p. 3). We are satisfied that the tariff language accomplishes that goal and that PG&E has correctly interpreted that language.

b. <u>Application to the "A" Series</u>

CFBF argues that the demand charge limiter should not be restricted to the "B" and "C" series of tariffs, for customers with connected loads of 35 horsepower or more, but customers on the "A" series of tariffs should also be eligible for the limiter. CFBF argues that there is no logic to restricting the limiter to customers with higher loads: if the purpose is to avoid the creation of seasonal billing demands when equipment is tested in the off-season, then it should apply to both small and large pumps.

PG&E responds by pointing out that demand meters are not installed for accounts on the "A" series. These accounts are required to pay a connected load charge that effectively includes a seasonal billing demand every month, regardless of the customer's actual demands. These customers tend to have a more intermittent load than larger facilities, and an unvarying connected load charge is assessed to collect noncoincident capacity costs. If the demand charge limiter applied to these customers, as CFBF proposes, collection of the noncoincident capacity costs from these customers would be eroded.

Because these customers do not have demand meters, we agree with PG&E that there is no practical way to apply the demand charge limiter. One of the components of the calculation of the limiter, the seasonal billing demand, can not be determined without a meter. We will not adopt CFBF's proposal.

c. <u>Replacement by an On-Peak Rate Limiter</u>

DRA believes the demand charge limiter currently applied to agricultural schedules is not based on costs. It therefore recommends phasing out the demand charge limiter and replacing it with the cost-based on-peak rate limiter of the large light and power schedules. In this proceeding, DRA recommends increasing the demand charge limiter by 5% over the cap used in the intraclass revenue allocation within the agricultural class.

PG&E does not oppose DRA's proposal, but it raises several points that may need further consideration. The proposed on-peak rate limiter would require seasonal users to pay noncoincident demand charges based on their seasonal billing demand, and off-season demand would not be forgiven by application of the demand charge limiter. This feature is more cost-based than the current limiter, but it moves against the Commission's stated intent in adopting the demand charge limiter.

In addition, applying the current on-peak rate limiter of the large light and power class to agricultural customers could allow some customers to avoid some of the noncoincident demand charges and peak demand charges. This avoidance would not be cost-based. PG&E suggests that the limiter may need modification to eliminate this possibility.

For the next rate case cycle, we believe that we should retain the demand charge limiter for the agricultural class with the increases advocated by DRA. This class has recently experienced an extensive restructuring of its rates, and our revenue allocation policy promises further rate increases in the future. The demand charge limiter is a modest attempt at mitigating one charge for customers with consumption in only one season, and we believe it is desirable to retain this limiter for the next three years. PG&E has pointed out some potentially perverse incentives associated with the on-peak rate limiter. We suggest that PG&E and DRA consider this matter more extensively and bring a more developed proposal to the next general rate case.

6. TOU Energy Charges

PG&E and DRA agree that TOU energy charges should be set so that the average rate in each TOU period is proportional to the combined marginal cost of energy and coincident capacity for each TOU period.

We will adopt the recommendations of these parties.

7. TOU Metering

PG&E and DRA agree that the incremental cost of TOU metering above standard meter costs should be added to allocated revenues for TOU schedules to produce the total revenue requirement. The parties further agree that the meter charges on TOU schedules should be set at the incremental cost of TOU metering, rounded to the nearest five cents.

We will adopt these parties' recommendations.

8. Setting the Level of Rate Components

PG&E and DRA agree that energy and on-peak demand charges should be set residually to collect revenues equal to the total revenue requirement minus the revenue from customer charges, maximum demand charges, and meter charges. Once on-peak demand charges are established, both DRA and PG&E set the on-peak energy charges on TOU schedules residually from the revenue allocated to the on-peak period.

We will adopt this approach.

9. Schedule AG-5

a. Rate Ceiling

PG&E initially proposed to limit rates for Schedules AG-5B and AG-5C by the estimated cost of diesel-fueled pumping. PG&E reasoned that limiting these rates to the cost of the competitive alternative would avoid bypass by agricultural customers. ACWA and PUPC support this proposal.

PG&E estimated the cost of diesel-fueled pumping as 7.4 cents/kWh and set the competitive ceiling for rates under these schedules at that level. ACWA estimates this cost to be 5.5 to 6 cents/kWh, and recommends this level as the rate ceiling. PUPC takes the view that the ceiling should be the average of the competitive price, which estimates as 6.1 cents/kWh, and these schedules' full EPMC share of the class revenue responsibility.

PG&E, however, has backed away from its initial proposal and now supports DRA's position. DRA approaches the problem of bypass by diesel-fueled pumps by proposing that Schedules AG-5B and AG-5C should receive their full EPMC shares of the agricultural class' revenue allocation. This approach results in a rate that is above marginal cost but competitive with diesel- or liquid petroleum-fueled pumping, according to DRA and PG&E.

PG&E adds that DRA's method spares parties in future general rate cases from the need to litigate the elements of the costs of competitive pumping fuels, and it avoids the need for farmers to negotiate special contracts to receive a competitive rate. PG&E also points out that DRA's approach, even at the highest levels of increase in revenue requirement considered in this case, results in rates that are no more than eight mills over the rates recommended by ACWA and PUPC.

We find that DRA's approach is simple and results in rates that appear to be competitive with the diesel or liquid petroleum alternatives. DRA's recommendation also avoids the need for subsidies by other customers. We will adopt DRA's recommended approach of giving Schedules AG-5B and AG-5C their full EPMC shares of the agricultural class' revenue allocation as the best way of addressing the issue of bypass by agricultural customers.

b. Minimum Bill

DRA and PG&E agree with PUPC's point that the minimum bill creates adverse and unintended consequences for customers on the AG-5 schedules. We will adopt their recommended solution and eliminate the minimum bill for Schedules AG-5A, AG-5B, and AG-5C.

10. Schedule AG-6

Schedule AG-6 was established as an interim schedule to accommodate customers who were waiting for the installation of TOU meters needed for service on Schedule AG-5. PG&E requests permission to continue service under Schedule AG-6, which was intended to be eliminated after December 31, 1989, for up to two billing cycles after the customer requests service under Schedule AG-5. PG&E is unable to keep up with the demand for TOU meters created by customers who desire to convert from Schedule AG-6 to Schedule AG-5. PG&E believes Schedule AG-6 continues to be effective in combating bypass for customers who are awaiting installation of TOU meters.

DRA supports PG&E's request, provided that all customers on Schedule AG-6 as of January 1, 1990 are converted to TOU schedules by May 1, 1990. PG&E agrees to this condition.

CFBF also believes Schedule AG-6 should continue until all agricultural customers who have signed up for service on Schedule AG-5 can have TOU meters installed.

We will adopt PG&E's proposal and allow PG&E to continue service under Schedule AG-6 for up to two billing cycles after a customer requests service under Schedule AG-5. PG&E should install the necessary TOU meters by May 1, 1990 for all customers on Schedule AG-6 as of January 1, 1990.

11. Interim Rate Schedules

CFBF argues that the pace of converting customers from Schedule AG-1 to new TOU schedules will accelerate, exacerbating an existing backlog in the procurement and installation of TOU meters. Because PG&E will be unable to accommodate all requests for conversion to TOU schedules within a reasonable period after the request, CFBF believes an interim rate schedule is necessary.

CFBF notes that several parties support the continuation of Schedule AG-6 until parties who have requested conversion to Schedule AG-5 can be accommodated. CFBF's proposed schedule would serve the same function for customers served on Schedule AG-1 who request service under the TOU Schedules AG-R, AG-V, or AG-4.

CFBF supports its request by noting that PG&E proposes to install only 2000 TOU meters for agricultural customers in the test year. Conversion requests have been coming in at about 1500 per month, however, and agricultural customers used up their allocation of TOU meters for 1989 by early February.

PG&E opposes CFBF's proposal for two chief reasons. First, CFBF proposes to open its interim schedules to customers of less than ten horsepower of connected load who are not obligated to convert to TOU schedules when meters are available. TOU service to such small customers is not normally cost-effective. Because the proposed rates are not cost-based, they will result in a revenue shortfall, at the expense of other customers.

Second, PG&E argues that the meter backlog is manageable and does not require a special interim rate. For customers requesting service on Schedules AG-4, AG-V, or AG-R, the backlog was 783 meters as of the end of May 1989. The current average delay between a customer's request for a TOU schedule and installation of a TOU meter is 30 days. Thus, the rationale for CFBF's proposal does not stand up to the facts.

DRA expresses interest in CFBF's proposal, but opposes its adoption in this rate case. DRA argues that the proposal was submitted well after the deadline for testimony by intervenors, and it should properly be submitted as part of the next rate design window. DRA also expresses concern about the specific structure of CFBF's proposed rates.

We are concerned about the delay in installing TOU meters, but we do not feel the interim rate proposed by CFBF is justified at this time. PG&E presented testimony in rebuttal to CFBF's proposal that stated that it had installed over 14,000 TOU meters for agricultural customers in the first half of 1989. The backlog for the schedules that are the target of CFBF's request seems manageable, and the average delay is within the range CFBF defines as reasonable and timely.

To make sure that adequate progress continues to be made in converting customers to TOU schedules, we will direct PG&E to present a report on this issue in early 1990. The report should state the number of agricultural TOU meters installed in 1989, the number of requests for conversion received in 1989, by month and by schedule, the backlog by schedule existing at the end of 1989, and the average delay in responding to a request for conversion. The report will be due on March 15, 1990, and should be served on CFBF, PUPC, ACWA, DRA, and any other party making a specific request to PG&E.

12. Proposed Schedule AG-7

PUPC proposed a new Schedule AG-7, with three declining load factor energy prices in the summer off-peak period and no minimum bill. The purpose of this schedule is to replace Schedules AG-4 and AG-5 for customers who migrate between these two schedules on an annual basis. The schedule would also avoid some of the unintended problems created by the minimum bill.

PG&E finds PUPC's concept to be worthy of further consideration, but it believes adoption of this schedule now is premature. Removal of the minimum bill for Schedule AG-5 will allay many of PUPC's concerns. But the benefits of this schedule have not been shown, and the fact that it is not cost-based leads PG&E to urge its rejection. PG&E thinks that the concerned parties should consider the purpose of the proposed schedule and perhaps introduce new rate options as part of the next rate design window.

DRA also supports PUPC's goals, but opposes adoption of Schedule AG-7 at this time. DRA opposes the declining block structure and rates that are not cost-based. DRA also believes the recommended elimination of the minimum bill for Schedule AG-5 will satisfy some of PUPC's concerns.

We will not adopt the proposed Schedule AG-7. We have decided to eliminate the minimum bill for Schedule AG-5, which accomplishes part of PUPC's purpose. If this action is not sufficient, additional rate options may be proposed as part of the next rate design window.

13. Interruptible Rates

PG&E proposes to eliminate its Agricultural Interruptible Project if the results from 1988 and 1989 show no improvement over 1987's cost-effectiveness and load impacts.

DRA opposes eliminating this option and proposes offering interruptible rates based on the old Schedule PA-4 as part of Schedules AG-R, AG-V, and AG-4. Any difference in customer service expense connected with providing interruptible service would be recovered in an interruptible service charge. DRA suggests that the cost-effectiveness of this program could be improved if credits are based on performance, rather than participation, and if credits are set equal to PG&E's avoidable generation, transmission, and distribution costs.

PG&E responds that DRA's proposals are a step away from cost-based rates, and that if an interruptible rate is offered, incentives should be based on the marginal costs adopted in this case, not on the rates of old Schedule PA-4.

We agree with DRA that it is important to develop options that may help the agricultural class reduce its contribution to the system's peaks. We also note that interruptible rates for agricultural customers were stimulated by passage of AB 2882 in 1986. PG&E argues that the legislation required it to develop economically feasible interruptible rates, and its experience has shown that these rates are not cost-effective.

We believe the interruptible program for agriculture should continue, and PG&E should strive to improve the cost-effectiveness of the program. We agree with PG&E, as does DRA in its reply brief, that the incentives should be based on the marginal costs adopted in this case. DRA suggests ways to improve the cost-effectiveness of the programs. We will direct PG&E to continue the agricultural interruptible program for this rate case cycle at a minimum of the current level of participation. The interruptible credit should be paid on the basis of performance, rather than participation. In addition, PG&E should consider DRA's recommendations on the interruptible service charge and make any appropriate proposals for this change in the next rate design window.

G. <u>Streetlighting</u>

Streetlighting is a unique customer class because customers have the option of either owning or renting certain facilities from PG&E. Service is provided under four schedules, with numerous different rates for different types of lights, different wattages and voltages, and different classes of service, which vary with specific facilities owned by the utility. Ex. 264, pp. 4-8 sets out a description of various rates provided to this class. In broad terms, Schedule LS-1 applies to streetlights with facilities that are primarily owned by PG&E. Service for streetlights that are owned by the customer is covered under Schedule LS-2. The customer usually owns the fixtures, poles, and interconnecting circuits for service under LS-3, and PG&E provides energy to one or more central points. Schedule OL-1 supplies service for outdoor area lighting not covered by other schedules.

1. <u>Facilities Charges</u>

Charges for streetlighting service have two basic components. Energy charges include costs included in the company's results of operations that are allocated as part of the revenue allocation. Energy charges for streetlighting include some charges not strictly related to energy, and energy rates are assessed as a flat monthly charge. Facilities charges cover the capital and maintenance of equipment like poles and lamps. All parties agree that facilities charges should be excluded from the revenue allocation, because these facilities are unique to the streetlighting class. We have already discussed and resolved, in the discussion of marginal customer costs, the issue of distinguishing between facilities-related and customer-related equipment and costs.

The parties differed strenuously on how to develop facilities charges. The parties split into camps supporting two methods described by some of the most awkward abbreviations known to public utility regulation.

a. PG&E

PG&E relied on the method adopted in its last general rate case decision, the original cost less depreciation-replacement cost new (OCLD-RCN) method. This method sets facilities charges in two steps. First, it determines a revenue requirement for the streetlighting class by applying the authorized rate of return to the net book value of the plant making up the streetlighting facilities owned by PG&E. Net plant is determined by taking the original cost of these facilities and subtracting the appropriate accumulated depreciation. The second step allocates the resulting revenue requirement to the various schedules, lamp types, and lamp sizes based on the current replacement costs of the facilities needed for that particular service.

PG&E believes that this OCLD-RCN approach is consistent with the marginal price principles relied on by the Commission in recent years. It amounts to a miniature ratemaking of the sort followed in the remainder of this case. A revenue requirement is determined according to depreciated capital investment and related expenses, and the responsibility for meeting that revenue requirement is allocated to various classes and schedules according to the incremental cost of providing the corresponding service.

b. Cal-SLA and DRA

Cal-SLA and DRA support an approach designated as the replacement cost new-economic carrying charge (RCN-ECC) method. This method attempts to develop an equivalent to a rental charge for PG&E's facilities. It begins with the current cost of replacing the various elements of the streetlighting facilities and calculates an economic carrying charge so that the costs of the facilities are recovered through a level charge over the equipment's expected useful life.

These parties believe that a simulated rent is the appropriate facilities charge for the streetlighting class, because customers have the option to purchase some of the facilities needed to serve them. This adds an element of competition, and the Commission should ensure that the determination of the regulated facilities charge does not inadvertently encourage the customer either to purchase or not to purchase the equipment.

Cal-SLA also believes the Commission has endorsed the RCN-ECC method, because it was adopted in the two most recent general rate cases, for Edison and SDG&E.

c. PG&E's Criticisms

PG&E argues that Cal-SLA and DRA apply the RCN-ECC method in a way that loses sight of the distinction between revenue allocation and the subsequent application of a rate design. The resulting rates are based on rental charges, a proxy for marginal costs, but these parties make no attempt to ensure that the revenue requirement associated with streetlighting services is recovered in rates to that class.

PG&E estimates, without direct challenge from any party, that the revenue requirement for the streetlighting facilities is about $25 million, but the rates that result from the RCN-ECC method bring in revenues of only $13 to $16 million (DRA and Cal-SLA differ in the components of their respective facilities charges). These parties have no proposal on how to recover this shortfall, and DRA even denies that a shortfall exists. PG&E believes that applying the RCN-ECC method in these circumstances leads to a subsidy of streetlighting customers by other customer classes.

PG&E acknowledges that the RCN-ECC method was adopted in Edison's and PG&E's recent general rate case decisions. PG&E points out, however, that in the Edison case the Commission adopted this approach because Edison's accounts did not record original cost and depreciation in a way that made it practical to use the OCLD-RCN method. In the SDG&E case, the parties did not dispute this issue, and the decision is silent about both the RCN-ECC method and the reasons for adopting it. PG&E believes that D.86-12-091 remains the Commission's most recent discussion of the appropriate method for determining facilities charges.

PG&E also reacts to the suggestion that facilities charges equivalent to rent are needed to avoid bypass by streetlighting customers. Customers purchasing streetlighting facilities do not leave the system entirely; they continue to buy energy from PG&E. Purchases reduce the capital costs associated with streetlights and reduce the revenue requirement for this class. If other customers are subsidizing the capital costs for streetlighting facilities, then these other customers will benefit when the facilities are purchased by the streetlighting customer. There is no need to attempt to set facilities charges at marginal cost, unadjusted for the class' revenue responsibility, because other customers are not harmed, as they are in the case of bypass by industrial customers. PG&E contends that the logic of the RCN-ECC approach fails.

d. <u>Cal-SLA's and DRA's Criticisms</u>

DRA and Cal-SLA believe the Commission indicated its preference for the RCN-ECC method in Edison's and SDG&E's general rate case decisions.

PG&E's concern about a subsidy from other customers is misplaced, according to these parties. There is no evidence that any such subsidy exists, because PG&E's determination of revenue requirement relies on the OCLD approach and on the reasonableness of minor plant accounts that are too small to be subject to normal review. DRA argues that the revenue requirement for streetlighting facilities should be determined by the RCN-ECC method, and its recommended rates are designed to recover that revenue requirement.

The Commission has repeatedly stated that revenue allocation and rate design should be based on marginal costs, and the rates developed by DRA follow that principle.

DRA also argues that the rental charge approach it advocates recovers the full capital cost of equipment over the useful life of the facilities. The fact that the timing and pattern of recovery may differ from PG&E's proposal does not constitute a subsidy or a revenue shortfall.

e. <u>Discussion</u>

It is true, as DRA points out, that we have repeatedly stated that marginal cost principles should guide our revenue allocation and rate design. The ultimate goal of ratemaking, however, is to set rates that recover the utility's reasonable revenue requirement. Although rates should be set according to marginal cost principles, it is extremely rare for marginal costs to equal the exact amount of the revenue requirement. Thus, it is necessary to scale marginal costs in developing rates so that the revenue collected through rates equals the revenue requirement. Our goal in revenue allocation and rate design is therefore described as setting rates based on an <u>equal percentage</u> of marginal costs.

It appears that the RCN-ECC approach to setting facilities charges leads to rates that approximate marginal costs without any attempt to relate those costs to the appropriate revenue requirement. To the extent that a shortfall exists, a subsidy from other ratepayers results. Our goal is and should continue to be to minimize subsidies from one group of customers to another.

DRA denies the existence of any such subsidy by suggesting that the revenue requirement calculated by PG&E is erroneous. However, DRA does not directly recommend a disallowance that would be consistent with its suggestion. Instead, it suggests that PG&E's proposed revenue requirement is faulty because it is based on small plant accounts that DRA did not review for reasonableness. It also asserts that DRA did not have reason to review PG&E's OCLD calculations in detail.

DRA's arguments are disingenuous. The OCLD approach has long been a standard regulatory approach to the calculation of revenue requirements. The fact that PG&E proposed facilities charges based on this approach in its application filed in December 1988 should have given DRA reason enough to examine PG&E's method. Although we recognize the severe constraints on DRA's time, the suggestion of a $12 million subsidy or hidden disallowance seems to provide sufficient reason to examine the pertinent plant accounts, even if the amounts in those accounts are relatively small.

DRA and Cal-SLA assert that use of a rental charge to establish facilities charges is necessary to avoid inappropriately influencing the customer's decision whether or not to purchase the facilities. These assertions carry some weight, but the underlying premises are faulty. As PG&E points out, if other customers are currently subsidizing the capital costs of streetlighting facilities, then other customers will gain to the extent that the higher charges resulting from PG&E's approach encourage customers to purchase facilities.

In addition, DRA and Cal-SLA have not justified setting rates equivalent to marginal costs. Even when it is apparent that bypass by industrial customers would harm other ratepayers, we have not automatically authorized rates at marginal costs. We have only permitted utilities to negotiate individual contracts with customers who can present a legitimate threat of bypass. Even for those customers, we have allowed utilities to negotiate rates that must, at a minimum, recover the costs of producing the power sold under the lowered rates, and we require utilities to set rates in the special contracts as far above those costs as is consistent with retaining the customer on the system (see D.88-03-008, mimeo. pp. 6-7, 36, 40). DRA and Cal-SLA have not shown, first, that other customers are harmed by purchases of streetlighting facilities, and, second, that rates set at marginal costs are necessary to avoid those purchases. Without a better showing, we are reluctant to adopt the rates that result from these unsupported premises.

We continue to agree with the points we made when we last considered this issue in detail, in D.86-12-091:

> "In choosing between these two approaches our goal is to adopt a street lighting rate design methodology consistent with that used for other rate classes. We believe this is best accomplished by using OCLD to determine the revenue requirement for street lighting facilities and a carrying charge based on RCN to allocate the revenue among the facilities.
>
> "Since these end use facilities are unique to the street lighting class, we believe that no other customer class should bear any burden or reap any benefits from street lighting rates. Accordingly, we will view the street lighting revenue requirement as being analogous to PG&E's overall revenue requirement. Both should be based on an embedded cost of service methodology to insure equitable rates. However, once the revenue requirement is established..., a marginal cost methodology should be employed to allocate revenues.
>
> "Therefore, we will adopt PG&E's OCLD methodology, adjusted to reflect the adopted rate of return in PG&E's GRC, to establish the revenue requirement for street lighting facilities. To properly allocate these revenues to the various facilities we will develop annual carrying charges based on RCN and the rate of return adopted in the GRC, with no return on contributed plant." (D.86-12-091, mimeo. pp. 86-87.)

PG&E has followed these directives, and we adopt its approach to calculating facilities charges for the streetlighting class.

f. Maintenance Charges

A charge for maintaining facilities is developed as a component of the facilities charge. Based on the discussion by Cal-SLA, it appears that PG&E and DRA differ in their adjustments of the basic maintenance charge to account for A&G overhead. DRA uses the A&G factor for the entire PG&E electric system. PG&E's recommended factor was developed specifically for the streetlighting class for use in calculating maintenance charges. Cal-SLA supports PG&E's approach.

We will adopt the A&G adjustment used by PG&E. This figure appears to reflect more precisely the A&G associated with the maintenance of streetlighting facilities.

g. Phase-In

Because of a miscalculation in PG&E's last general rate case, the facilities charges PG&E proposes in this case are considerably higher for some customers than present charges. To avoid undue effects on some customers, PG&E proposes a plan to phase in the increases.

PG&E's proposal was not opposed by other parties who supported lower charges. The proposal phases in the increases over three years for most customers, and over up to six years for customers facing the highest increases.

We will adopt PG&E's proposed phase-in for this rate case cycle (see Appendix J). We note that our decision to move the streetlighting class toward full EPMC over the rate case cycle will significantly counteract the phase-in of higher facilities charges. We will also reserve judgment on whether the phase-in will be continued over a second rate case cycle. We note that the net plant associated with these facilities has declined greatly in recent years, and a lower net plant and associated revenue requirement may affect the need and pace of the continued phase-in at the time of the next general rate case.

2. Energy Charges

Because of the nature of streetlighting service, energy charges are assessed at a flat monthly rate. All costs that are included in the EMPC allocation for streetlighting, including energy, demand, and customer costs, are recovered through the energy charge. The allocated revenue requirement is divided by forecasted sales to arrive at the energy charges that apply to the various schedules and classes of streetlighting service.

Cal-SLA argues that energy rates for streetlighting should be based on marginal costs of the rates' components and an EPMC revenue allocation. In essence, any dispute concerning this issue really centers on the question of appropriate caps and movement toward EPMC. We addressed this issue under revenue allocation, and our resolution there makes it unnecessary to consider this issue further.

3. Customer Charge

Cal-SLA recommends adoption of customer charges based on marginal customer costs and the EPMC multiplier.

Streetlighting schedules have no explicit customer charge. Our discussion of marginal costs resolved the issues on calculating marginal customer costs for the streetlighting class. The allocation of marginal customer costs to the streetlighting schedules is governed by our decisions on revenue allocation.

4. Pole-Painting Fee

Based on an examination of its costs, PG&E proposes to raise the pole-painting fee from $0.62 per pole per month to $0.82 per pole per month. DRA supports this change. Cal-SLA recommends a fee of $0.74 per pole per month.

We will adopt PG&E's proposed fee.

5. **Elimination of Class B of Schedule S-1 for High Pressure Sodium Vapor Service**

Class B of Schedule LS-1 applies only to installations in service as of September 11, 1978. PG&E proposes to transfer the high pressure sodium vapor facilities served under this schedule and class to Class A, which has identical rates for this type of service. No party opposes PG&E's proposal.

We will adopt PG&E's proposal.

6. Adjustment for Daylight Savings Time

Cal-SLA testified that PG&E did not take daylight savings time into account in developing the TOU fractions incorporated in streetlighting rates. Correcting for this oversight shifts more of the class' energy consumption to off-peak hours. No party contested Cal-SLA's point.

We agree that the TOU fractions used in developing streetlighting rates should reflect the effect of daylight savings time.

XI. Demand-Side Management

Demand-side management (DSM) refers to programs that emphasize reducing or manipulating demand to improve the efficiency of the operation of the utility's system and to bring the system's loads and resources into balance. As the term indicates, DSM is distinct from a utility's efforts to build or acquire generation resources to increase the supply of electricity or to obtain new supplies of natural gas. Demand-side options began receiving particular emphasis in the 1970s, as new sources of energy, especially electrical generation, took on increased economic and social costs. This Commission has long recognized the general principle that managing demand can be as effective as increasing supply resources, and demand-side alternatives often carry a lower economic and social costs. In an era of increasing domestic and international competition, California's outstanding economic strength and environmental protection rest, at least in part, on a foundation of energy efficiency. Considerable credit for those achievements can be given to demand-side programs financed by California's investor-owned utilities.

On July 20, 1989, the Commission held an en banc hearing at which we signalled the beginning of a new era for energy efficiency in California. In recent years utility investments in demand-side programs, and the energy savings from such investments, had declined. This was in part due to the Commission's and utilities' concerns about uneconomic bypass and also to the relaxation of the utilities' efforts in developing new energy efficiency programs. However, at the en banc hearing in July, we clearly stated our interest in reestablishing the leadership of California's utilities in helping customers reduce their energy bills and at the same time minimize environmental impacts caused by some forms of electrical generation.

DSM refers not only to efficiency improvements (getting equal or more work out of less energy), but also load management (shifting demand to lower the costs of serving customers), and related programs.

The issues in this case fell into four general areas: policy principles, cost-effectiveness, funding levels, and program design.

A. Funding, Evaluation, and Implementation Principles

DRA asks the Commission to adopt its proposed "Funding, Evaluation, and Implementation Principles" (FEIP) for DSM (Exhibit 110, App. A). The FEIP consist of some 65 individual tenets covering all aspects of PG&E's current DSM program. DRA's proposal aroused considerable controversy.

1. Positions of the Parties

a. DRA

DRA states that three considerations led to the development of the FEIP. First, DSM programs have become increasingly complex. Specific programs serve multiple purposes and have different types of effects on load. Second, in part because of this increased complexity, a greater need for consistency has arisen. Consistency in the treatment of DSM for the different utilities and in different proceedings will benefit all concerned, in the same way that development of standard practices for evaluating the cost-effectiveness of DSM programs has aided the utilities and the Commission. Third, at a time when the perception of and emphasis on DSM is changing, the FEIP help establish and clarify the purpose of DSM in the future.

DRA argues that a further need for the FEIP grows out of the Commission's commitment, as expressed in PG&E's last general rate case decision, to treat supply and demand resources equally. The FEIP attempt to ensure that supply and demand resources are given equal footing in the utility's plans.

The FEIP also try to ensure that money allocated for residential conservation, for example, is not spent on fuel substitution. The existing flexibility in transferring funds from one program to another has led to abuses, DRA believes. The FEIP further try to make sure that a utility does not intentionally underspend authorized funds without a substantial justification. An additional function of the FEIP is to identify more clearly the total resource cost (TRC) test as the primary measure of cost-effectiveness for DSM programs. The parties' use of various tests of cost-effectiveness has led to confusion in the meaning of cost-effectiveness as applied to DSM programs, DRA claims.

For each program area of DSM, the FEIP state a primary purpose and any applicable secondary purposes of the program. The tenets set forth guidelines for accounting for program costs, for the subsequent reporting of expenditures, and for future requests for changes in program participation or funding levels. The principles also try to clarify the relative importance of load impact estimates and cost-effectiveness in the evaluation of each program. The expected future direction of the program and the grounds for expansion or contraction of the program are also explained.

Several principles receive special emphasis from DRA, and are "absolutely critical" for the Commission to adopt:

> "1. Designation of energy efficiency incentive programs and load management programs as the appropriate sub-set of DSM which are intended to serve as alternatives to supply-side resource options...;
>
> "2. Explicit endorsement of the Total Resource Cost test as representative of the costs and benefits which should be used to compare DSM programs to supply-side options...;
>
> "3. Designation of the Electricity Report and Biennial Resource Planning Update proceedings as the appropriate forum for determining the level of funding for those programs evaluated as demand side alternatives to supply-side options...;
>
> "4. The delineation of guidelines for discretionary movement of funds between programs, and for expectations regarding expenditure levels relative to authorized levels...." (Opening Brief, p. 116.)

DRA makes clear that it intends to have the Commission adopt the FEIP in this proceeding for all energy utilities and all DSM programs. Even though this case covers only PG&E, all affected utilities made appearances in this case and attended the hearings when DRA's witness was cross-examined. Adopting the FEIP for all utilities ensures consistent application of a statewide policy.

b. PG&E

PG&E urges the Commission not to adopt the FEIP.

PG&E pursues DSM with five objectives in mind: first, to minimize the cost of providing energy service to customers; second, to enhance customer satisfaction with PG&E's service; third, to maintain the infrastructure of DSM programs to make sure they are available as short lead-time resources; fourth, to retain or increase sales when in the best interests of PG&E's customers; and fifth, to provide for flexibility in meeting uncertain future resource needs (Exhibit 11, p. 1-1).

PG&E particularly emphasizes the need for flexibility in DSM programs, so that programs and incentives can be adjusted to respond to unexpected capacity needs, energy costs, and other changes in energy markets. The FEIP will unduly restrict PG&E's ability to maximize the benefits of DSM programs. The FEIP also run counter to the Commission's previously stated view of the role of the utility's discretion in carrying out DSM programs.

PG&E further argues that the FEIP are ambiguous and incomplete and that they ignore the complexity of DSM programs.

DRA's specific emphasis on the TRC test comes at the expense of the Ratepayer Impact Measure (RIM), which has served as an important tool in evaluating DSM programs up to now. Yet the FEIP almost totally ignore the issue of the appropriate role of the RIM in evaluating DSM programs.

DRA has failed to explain and justify why these sweeping FEIP are necessary, in PG&E's opinion. One of the purported justifications, greater complexity in DSM programs, is precisely why it is important to maintain the utility's flexibility to respond to changing conditions. The other primary considerations behind the FEIP, consistency and clarity, can be addressed in a less overpowering fashion when the Commission considers DSM in the normal course of its oversight, such as in the periodic general rate cases.

Finally, PG&E believes it is completely inappropriate to develop a detailed policy framework, such as DRA proposes, in the context of a single utility's general rate case. The Commission recently convened an en banc hearing on DSM, and wide-ranging policy issues like those raised by the FEIP should be considered in a forum that allows participation by all interested parties, rather than in a single utility's rate case.

c. CEC

CEC supports certain of the principles proposed by DRA. and CEC focuses many of its comments on the specific tenets of the FEIP.

CEC agrees that decisions on long-run DSM programs should be made within a resource planning proceeding. However, CEC thinks it would be "needlessly duplicative" for this review to take place both in the CEC's proceeding to develop its Electricity Reports and in the Commission's Biennial Resource Plan Update proceeding. CEC suggests that the two agencies should eliminate this duplication by agreeing on the nature of the DSM analysis that each agency is responsible for and the role that each agency's decision would play in the other's proceeding.

CEC strongly endorses DRA's proposal to rely primarily on the TRC for evaluation of DSM programs. CEC also supports the provision that allows use of an alternative test embodying the principles of the TRC test.

With some reservations, CEC endorses DRA's proposal to develop longer-term funding authorizations for programs that can be counted as committed resource additions. CEC notes that long-term funding is a means to an end, and long-term funding should be tied to specific goals for saving energy and capacity. Thus, CEC views long-term funding not as a constant funding level but as the Commission's intention to continue financial support for these programs at a level appropriate to achieve the target savings. Savings levels will then dictate whether individual programs receive additional or reduced funding.

On the issue of redirecting funds among programs, CEC recommends requiring the utility to show that increased energy or peak demand savings will result from the redirection. In addition, the utility should show that no mandated programs, such as data collection or program evaluation, will suffer from the change. All parties to the original proceeding should be notified of the proposed redirection.

CEC does not oppose DRA's statements of the primary purpose of DSM programs, provided that the utility is allowed and encouraged to propose new programs. The stated purpose of the direct assistance program should be modified to state that funding levels for this program are tied to the needs of the disadvantaged customers, not to levels of funding for energy efficiency programs. Reporting requirements should be retained for information programs, not eliminated, as DRA proposes.

CEC opposes the proposed cap on new construction programs. CEC supports restricted funding for fuel substitution programs, but believes such programs should be allowed if they achieve both efficiency and environmental goals. CEC also supports the proposed restrictions on load building programs; if funded, the Commission should restrict its funding to short-term programs. The provisions for improving data collection and analysis and measurement and evaluation also receive CEC's support.

Finally, CEC agrees with DRA's statement that the lack of a forum for considering the relationship between natural gas and electric resources hinders an integrated evaluation of these two resources. CEC supports DRA's proposal to have the utilities file an analysis of these issues in connection with the California Gas Report.

d. Edison

Edison opposes adoption of the FEIP for four main reasons.

First, the recent en banc hearing on DSM eliminated any uncertainty that may have existed about the Commission's position on DSM programs and evaluation. The Commissioners made it clear at the July 20, 1989, hearing that they intend to continue to support energy efficiency programs in current and future proceedings. In addition, the Commission has acted effectively to control expenditure levels and prevent improper redirection of funds on a case-by-case basis, and there is no need for a new layer of regulation to address these issues.

Second, Edison agrees with PG&E that the issues raised by the FEIP are too broad to be addressed successfully in the general rate case of a single utility. Edison believes the BRPU proceeding is the best place to consider these principles.

Third, Edison disagrees with several of the proposed tenets and thinks the FEIP require further analysis.

Fourth, the FEIP encroach on the policy-making powers of the Commission and would have the Commission defer to DRA on policy matters relating to DSM programs. Edison urges the Commission to retain its ability to examine the merits of DSM programs on the basis of the latest information and policy objectives.

f. <u>SDG&E</u>

SDG&E argues that it is inappropriate to develop statewide policy, such as DRA proposes in its FEIP, in the general rate case of a single utility. Policy changes of this magnitude and scope should be addressed in a generic proceeding open to all affected utilities and other interested parties.

If policy changes like those incorporated in the FEIP are considered in general rate cases, SDG&E believes that general rate cases will become even more convoluted and unwieldy than they currently are.

SDG&E also points out that it did not have an opportunity to address the FEIP or to participate in their development. SDG&E first became aware of DRA's intent to apply these principles to all California utilities when DRA's witness stated so in his oral testimony.

SDG&E therefore urges the Commission to reject these policy changes in PG&E's general rate case and to consider these issues in a generic proceeding with the full participation of all interested parties.

g. ERA

ERA supports the FEIP as "clear and consistent guidelines for least-cost energy planning" (Reply Brief, p. 7). ERA thinks the FEIP will help the Commission take externalities into account in evaluating DSM programs.

2. Discussion

The controversy about DRA's FEIP has focused not so much on the specific principles DRA proposed as on whether or not we should adopt a set of explicit written principles for use in evaluating DSM programs.

We should clarify at the outset of our discussion that we believe we have already stated a series of principles for evaluating DSM programs. These principles have been set forth in the various decisions we have made on DSM issues over many years. Many of the tenets of the FEIP appear to be restatements of policy determinations we have already made and, to that extent, do not need to be adopted again by the Commission. DRA should delineate those portions of the FEIP that we have already adopted as our policy in prior decisions.

The issue the parties have addressed is thus whether we should continue to make policy in the context of individual cases or adopt written principles clearly stating our policies. We are sympathetic with the intent of the FEIP but, for a number of reasons, we do not feel comfortable adopting the entirety of the FEIP for all utilities at this time.

First, we do not agree that PG&E's general rate case is the appropriate forum for adopting general principles for all utilities. The mere fact that the major utilities filed appearances in this case and attended the cross-examination of DRA's witness does not provide adequate notice that issues directly affecting all California energy utilities would be considered.

SDG&E pointed out that it was not aware of DRA's intent to ask the Commission to adopt its FEIP for all utilities until DRA's witness stated that intent as part of his oral testimony. In these circumstances, we could not apply the FEIP to any utility other than PG&E.

Even focusing just on the FEIP for PG&E, we are concerned that explicit written principles may be too restrictive to account for changing circumstances. We have recently expressed an interest in giving utilities incentives to promote DSM programs[26], and we are aware that several parties are meeting to develop proposals on this topic. If we are able to incorporate incentives into our DSM programs, portions of the FEIP could become out-of-date within months of their adoption. In less dramatic fashion, other changes in circumstances could also come into conflict with the principles. While we are aware of some abuses of the traditional flexibility given to utilities on spending DSM funds[27], we are reticent to restrict the utilities' flexibility in program management at this time.

While deciding not to adopt the FEIP in their entirety at this time, we find portions not only useful but necessary to be adopted. The first two of the "absolutely critical" principles discussed in DRA's opening brief have much value. We agree that energy efficiency programs and load management programs are the

26 At the July 20 en banc hearing on the status of the Commission's DSM programs, a number of organizations, including many parties in this proceeding, expressed an interest in a "collaborative process" on DSM policies. This collaborative group has been meeting since July to formulate proposed policies and initiatives that will be presented to the Commission early next year.

27 In an advice letter filed November 8, 1989, PG&E is seeking authority to dispose of over $70 million of DSM funds which had not been expended.

appropriate portion of all DSM programs that are intended to serve as alternatives to supply-side resources. This is not meant to disparage other types of DSM--just because a program does not serve as an alternative to supply-side resources does not make it worthless. Many of these other programs, as DRA itself admits, serve useful purposes. But in considering programs that can contribute to deferring the need for new resources, we need to be selective, and thus we agree to adopt DRA's categorization.

The second critical principle asks for the Commission's endorsement of the Total Resource Cost test as "representative of the costs and benefits which should be used to compare" demand-side and supply-side resources. The TRC test is a comparison of the benefits of program-induced load reductions, valued at marginal or avoided costs, and total program costs, including participant costs, of installing and operating the efficiency improvements. The TRC cost-effectiveness determination, as embodied in the joint <u>CEC/CPUC Standard Practice Manual for the Economic Analysis of Demand-Side Management Programs</u>, appears to us to be the proper basis for evaluating the cost-effectiveness of demand-side resource options.

As to the two other critical principles identified by DRA, we recognize the potential benefit of using the BRPU proceeding as the forum for choosing programs and determining their funding levels. As the forum for the analysis of utility resource plans (based on the CEC's Electricity Report), the BRPU is also an ideal forum for other potentially long-term resource decisions. Despite its attractiveness and our interest in linking long-run supply and demand-side planning, we think DRA's proposal falls far short of the detail necessary for implementing the integration of what has traditionally been a general rate case decision into the BRPU.

In regard to the fourth principle, on the development of guidelines for the movement of funds between programs and spending amounts different from authorized levels, we are not inclined at this time to adopt DRA's recommendations. As stated earlier in this section, flexibility in allocating DSM funds is a traditional prerogative the Commission has afforded to utilities. It allows utilities to respond to circumstances between rate case cycles and to improve the performance of their DSM programs. Wo are disappointed that, over the last three years, PG&E has fallen short of DSM spending authorizations by over $70 million. The authorization of funds in a rate case is inherently an expression of the Commission's intent for the utility to pursue DSM programs at a level consistent with the funding commitment. While we do not wish to adopt DRA's proposals in this case, we would like to see a forum for focused analysis of DRA's proposals so that, if deemed necessary, the Commission could adopt some funding guidelines.

On both of these last "critical" principles, and the other FEIP not explicitly considered here, we would like to see their further consideration in another forum. We await the results of the collaborative process before deciding on a more rigorous approach, including the possibility of using whatever proceedings may follow from the collaborative process to consider these concepts.

B. Cost-Effectiveness

PG&E criticizes DRA for not following the cost-effectiveness tests of the Standard Practice Manual. The Standard Practice Manual was developed by DRA and CEC to allow for comparable cost-effectiveness evaluations of DSM programs. PG&E followed the manual and developed cost-effectiveness results for each of the four tests developed in the manual.

PG&E finds DRA's showing faulty on several counts. First, DRA emphasizes the TRC test and neglects the results of the RIM test. Second, although DRA did not develop its long-run marginal costs in time to perform the tests of the Standard Practice Manual for the electric DSM programs, it performed analyses based on tests that were not included in the manual. These methods, which modeled the operation of the system with and without conservation, have been considered for inclusion in the manual, but no agreement was reached about their use. Nevertheless, DRA saw fit to base its testimony on the results of these tests.

In doing so, DRA undermines its own arguments in favor of the FEIP about the need for consistency, PG&E argues. In the realm of cost-effectiveness tests, parties have agreed to a consistent approach, but DRA chose to ignore this consistency and to submit the results of a test not yet included in the manual.

Third, DRA based the cost-effectiveness analyses of its gas DSM programs on facility marginal costs. DRA included costs that are essentially embedded costs, not related to the commodity cost of gas. These costs should not be included in an cost-effectiveness analysis.

DRA defends its emphasis on the TRC test with two points. First, most costs of DSM programs are recovered in the first year of the program, but the benefits persist for a longer time. This mismatch of costs and benefits tends to lower the benefit-cost ratios of the RIM. Second, the current relation of marginal costs to average retail rates also leads to low benefit-cost ratios for the RIM. Emphasizing the TRC places more stress on the long-term benefits of DSM programs over short-term rate reductions. DRA believes this emphasis on the long term is appropriate, and it accordingly favors the TRC for evaluation of DSM programs.

ERA thinks that life-cycle costs should be the benchmark for evaluating all new programs and resources. Unless DSM programs can be compared over their useful lives, they will always be at a disadvantage in comparisons with supply-side resources. ERA also believes PG&E has underestimated its need for capacity, and this underestimation has in turn distorted PG&E's cost-effectiveness analyses.

We agree with PG&E that the emphasis in evaluating DSM programs should be on the tests set forth in the Standard Practice Manual. Additional information may be submitted, but parties proposing new tests or revisions to existing tests should pursue those changes within the structure established to develop and revise the manual. DRA has undermined its positions by not supplying results for the manual's tests while submitting the results of a new approach it favors.

We agree with DRA on the question of which of the tests of the Standard Practice Manual to favor. Under present circumstances, we will pay most attention to the TRC test. We will not ignore the RIM, but we think that the current relationship between average rates and marginal cost erodes the ability of the RIM to reflect accurately the effect of various DSM programs on ratepayers.

C. <u>Program Funding Levels</u>

PG&E proposes a total funding, including capital-related expenditures, of $120,191,000 for its DSM programs, broken down to $88,453,000 for electric DSM programs, and $31,738,000 for gas programs (Exhibit 43). On a comparable basis, DRA recommends a total budget of $130,562,000, consisting of $101,108,000 for electricity and $29,454,000 for gas (Exhibit 110, Tables A-1 and A-2). CEC primarily addresses electric DSM programs and recommends a budget of $69,034,000 (Exhibit 250, p. 3; Exhibit 249-A). ERA proposes a DSM budget totaling $132,268,000, with $99,490,000 devoted to electric DSM programs and $32,778,000 for gas. Other parties take issue with PG&E's requests for certain programs, and we will discuss their positions when we address those programs.

ERA believes PG&E has significantly overestimated its available resources for the future in its long-term plan, and that PG&E will need capacity as early as 1990. ERA advocates a vigorous program of DSM to fill the need for capacity and recommends particular emphasis on indigenous resources such as wind and solar generation.

1. Residential Conservation

a. Direct Assistance Programs

The Direct Assistance programs provide special conservation assistance, including free weatherization and high-efficiency appliances, to qualifying low-income customers.

(1) Positions of the Parties

PG&E proposes two subprograms for residential direct assistance. The Target Customer Direct Assistance Program (TCDAP) is designed to educate customers on efficient energy use and to install insulation and efficient devices in the homes of qualifying low-income customers. The Target Customer Appliance Program (TCAP) will repair or maintain appliances for qualifying customers, or help customers obtain efficient appliances when their old appliances are beyond repair.

PG&E proposes to consolidate the existing Direct Weatherization, Low-Cost Weatherization, and Community Weatherization programs under the TCDAP to reduce administrative costs and improve the Direct Assistance programs' cost-effectiveness. Because of increased efficiency, the budget for Direct Assistance is smaller than authorized in the 1987 general rate case, but the number of participants served by these programs would not change.

DRA supports PG&E's proposals.

CEC recommends a cut of about $5.5 million in Direct Assistance programs for electric customers. (CEC has no recommendation on the gas portion of this program.) PG&E's current weatherization programs have resulted in very small energy savings, less than $15 per year for each $400-500 spent on weatherization, according to a study performed by Cambridge Systematics, Inc. CEC believes PG&E should investigate the reasons for the low level of savings from these programs and restructure the weatherization programs to improve the programs' benefits. Only then should the Commission consider higher funding for these programs.

Cal-Neva opposes CEC's recommended cuts for four reasons. First, the study by Cambridge Systematics had many technical and statistical shortcomings that clearly lead to an understatement of the benefits to electric customers. Second, the cost-effectiveness approach applied to low-income programs is different from and more strenuous than the tests for other programs, resulting in estimates that are biased against the low-income programs. Third, CEC does not consider what has been called the rebound effect: weatherization improvements may lead low-income customers to trade increased comfort for reduced energy bills. CEC's analysis does not consider or assign a value to this increase in comfort, although in another context CEC considers and accepts the increase in consumption resulting from a rate subsidy to low-income customers. Cal-Neva finds CEC's positions inconsistent. Fourth, no value has been assigned to the environmental effects of energy consumption; the benefits from weatherization programs would increase if environmental costs and benefits were considered.

ERA also opposes any cut in the budget for the Direct Assistance programs, and ERA recommends a budget of $21,000,000 for these programs. PG&E's proposals rely too heavily on one flawed study, the study performed by Cambridge Systematics, to evaluate the cost-effectiveness of these programs. Furthermore, like Cal-Neva, ERA points out that traditional cost-effectiveness studies do not take into account factors like the comfort level of customers or the environmental effects of additional electrical generation. ERA believes the Commission should instruct PG&E not to emphasize the Low-Cost Weatherization program over the Direct Weatherization program. The zero-interest loan program (ZIP) and the Cashback rebate program should be revived, because residential customers, particularly low-income customers, have been particularly affected by recent rate increases.

TURN supports PG&E's funding level, but it agrees with ERA that the Commission should emphasize residential, rather than industrial, programs, and PG&E should not shift its weatherization emphasis to use more customer-executed audits at the expense of comprehensive audits.

(2) Discussion

We will adopt the funding levels for these programs recommended by PG&E and DRA. CEC's proposed cuts in the electric portion of these programs are based on a single study with some apparent shortcomings. In any event, PG&E has proposed to restructure these programs in a way that should improve the cost-effectiveness. Fairness requires maintaining programs like the Direct Assistance programs for low-income customers who are unable to take advantage of our other DSM programs. Because of these equity concerns, we agree with DRA's FEIP that "positive cost-effectiveness results should not be considered a necessary requisite for program continuation."

We will adopt PG&E's proposed expense of $17,636,000 for the electric portion of the Direct Assistance programs, and $13,291,000 for the gas portion, for a total of $30,927,000.

b. Superweatherization Program

ERA believes PG&E should develop a pilot program of "superweatherization" for extreme climate zones. Superweatherization includes such measures as efficient windows, timers on water heaters, setback thermostats, and insulation of nonstandard ceilings. ERA states that such a program is cost-effective in those areas and that similar programs have been carried out in other parts of the country.

PG&E responds that this program would increase costs with no corresponding benefits and would decrease the cost-effectiveness of an already marginal weatherization program.

In light of the conflicting evidence on the cost-effectiveness of the weatherization program, we believe that PG&E should concentrate on improving the effectiveness of the existing program before pursuing superweatherization. PG&E may, however, conduct the pilot program suggested by ERA if it believes that superweatherization could help improve the effectiveness of its weatherization program.

c. Natural Gas Home Program

The Natural Gas Home Program is a fuel substitution program that provides incentives to builders to install efficient natural gas space and water heating and gas appliances in new houses, rather than less efficient electric appliances.

(1) Positions of the Parties

PG&E requests $2,669,000 to continue this program. It cites several benefits. The incentives help overcome market barriers to the installation of gas service, and help ensure that gas service is extended to new developments. Because of the high cost of retrofitting, the cheapest time to extend gas lines into new developments is when they are under construction. In addition, by increasing the end-uses available to these customers, the program helps spread capital costs and decrease rates for other gas customers. The program passes the TRC test, although not under DRA's flawed analysis, which used higher marginal gas costs and outdated costs for SMUD's electricity. DRA's concerns about a possible incentive war with SMUD are unsupported and would amount to the Commission's abdicating its responsibilities in favor of SMUD.

CEC also favors this program. The program is aimed at a market failure caused by builders who make decisions based on lowest first cost, rather than life-cycle costs. CEC suggests that the program can be improved by offering information and incentives to encourage installation of appliances exceeding current efficiency standards. CEC recommends funding of $4,240,000 for this program.

TURN supports this program subject to two restrictions. First, TURN believes the program should be limited to developments where the developers have requested gas service only for water heating. PG&E justified its request by stating that it does not recover its costs when it extends gas service to new developments for use solely in water heating. TURN's limitation reflects PG&E's justification. TURN's second limitation is that the program should be offered throughout PG&E's service territory. TURN thinks that PG&E's rationale for the program applies equally to PG&E's and SMUD's service territories.

ERA recommends a budget of $3,036,000 for this program.

DRA thinks this program should be eliminated. DRA refers to its FEIP, which state, "Programs for the promotion of gas usage in the service territory of a municipally owned electric utility shall not be authorized without the endorsement to the municipal utility." DRA fears that programs such as the Natural Gas Home program could lead to incentive wars with the municipal utility. DRA thinks that PG&E has not demonstrated that natural gas is the preferred fuel in these situations. Furthermore, to the extent that PG&E justifies its program as compensating for SMUD's promotional activities, the Warren-Alquist Act authorizes CEC to object to promotional activities by electric municipal utilities.

(2) Discussion

We will authorize funds for the Natural Gas Home program at the level requested by PG&E.

We are concerned, however, about DRA's belief that we are funding an incentive war with SMUD. This is not our intention nor the purpose of this program. The primary purpose of this program is to overcome market barriers to installing efficient natural gas appliances, rather than less efficient electric appliances that may have lower initial costs. DRA hints that it would lower its opposition to this program if it were coordinated with SMUD's electric conservation programs. We encourage PG&E to seek such coordination.

In light of the conflicting results of the cost-effectiveness evaluations, we are reluctant to provide funds at the level suggested by CEC. However, PG&E should seek to improve the effectiveness of this program by providing builders with information about appliances that exceed existing efficiency standards.

The authorized expense for the Natural Gas Home program is $2,669,000.

d. Electric Incentive Program

PG&E proposes a new fuel substitution program to offer incentives for the installation of electric heat pumps in areas without natural gas service. The heat pumps would help deter uneconomic bypass by customers heating with wood or liquid petroleum gas (LPG). PG&E requests $1,060,000 for this program.

DRA opposes the program. DRA classifies this program as load building, and DRA views most load-building programs as an inappropriate trade of short-term gains for the certainty of long-term costs (Exhibit 110, p. V-18).

TURN also opposes this program as an attempt to build winter load.

We conclude that PG&E has not adequately justified the need for this program. In Exhibit 11, it omits a cost-effectiveness analysis for this program; in Exhibit 64, it states without further discussion that the program passes the participant, TRC, and RIM tests. Although developing marginal costs for LPG and wood may be difficult, some discussion of costs should have been offered in support of its proposal. PG&E states that any increased load would occur in the winter, when PG&E has sufficient capacity, but again it offers no facts to support its statements. According to PG&E, heat pumps are used for both water heating and space heating; certainly the water heating function will lead to some increased peak load.

PG&E has not sufficiently supported its request, and we will not authorize funds for this program.

e. Efficient Outdoor Security Lighting Program

PG&E requests $131,000 for an Efficient Outdoor Security Lighting Program. DRA and TURN oppose this program as unwarranted load building. ERA thinks the program should be promoted under existing marketing budgets and not funded as a DSM program.

PG&E argues that the purpose of this program is not load building but encouraging the replacement of existing incandescent lighting with more efficient lighting devices. PG&E's assertion is contradicted, however, by its own estimate that the program would increase electricity consumption both in its first year and over the life cycle of the lights.

PG&E has failed to justify this program, and we will not authorize it.

f. One-Stop Energy Shop

PG&E originally requested $200,000 as part of its residential information program for expenses associated with its One-Stop Energy Shop. In its comments on the Proposed Decision, PG&E states that it has decided to close the shop at the end of 1989. It requests the $200,000 budgeted for the shop for other appliance information programs.

We believe that the budget we approve for information programs is already adequate for the purposes proposed by PG&E. We will remove the $200,000 earmarked for the One-Stop Energy Shop from the authorized DSM budget.

2. Other Conservation Programs

a. Energy Efficiency Incentive Programs

These programs offer rebates and other incentives to commercial, industrial, and agricultural customers for installing equipment that improves the efficiency of energy use. DRA recommended substantially larger budgets for these programs than PG&E.

(1) Positions of the Parties

DRA urges the Commission to authorize about $17 million more for incentive programs than PG&E requested. DRA offers several reasons in support of its recommendation.

DRA first submits its general principle that DSM programs should be evaluated under the TRC test. Incentive programs have very high benefit-cost ratios. In addition, DRA supplemented its cost-effectiveness analyses by using production simulation models to test the effects of implementing its recommendations for PG&E's system. DRA concludes that sustained support for the conservation options it proposes could serve as a cheaper alternative to PG&E's planned purchases from the Pacific Northwest and to operation of conventional thermal power plants.

DRA also notes that PG&E's requests for the test year were geared to its expected expenditures for 1989. This level of expenditure, however, is much lower than the levels in recent years for almost every program element.

DRA's essential position is that DSM options can and should compete with more conventional resources if they are given sufficient funding over a reasonable period of time. If the Commission is willing to sustain DRA's recommended level of expenditures for these incentive programs for six years, DRA believes these programs will be less expensive than the conventional options in PG&E's resource plan.

PG&E criticizes DRA's recommendations because they were based on analyses that departed from the tests of the Standard Practice Manual. Production simulation models not covered by the Standard Practice Manual supported many of DRA's recommendations; at the same time, DRA ignored the results of the RIM, which is a standard measure of cost-effectiveness.

DRA also bases its recommendation on the technical potential of various DSM measures. PG&E thinks technical potential by itself is not a sound foundation for program design and funding. Factors such as customer preferences and market saturation also play an important role in developing efficient and effective DSM programs.

Because the elements of the energy efficiency incentives do not fare well under the RIM, PG&E requests funding equal to the current level of incentive activity. This level will maintain the existing infrastructure and allow expansion of the program when market conditions warrant it.

CEC supports DRA's position on electric energy efficiency programs. CEC agrees with DRA's argument that large-scale application of certain energy incentive programs will result in increased energy savings. CEC notes that the commercial sector has a great potential for increased efficiency.

TURN rejects DRA's proposals for increased commercial and industrial incentives. TURN thinks that these customers are in a position to finance their own investment in these devices if the savings are as great as DRA states. In addition, TURN thinks that a growing private industry will evaluate and carry out commercial and industrial conservation measures in exchange for a share of the savings. Thus, DRA's increased funding is unnecessary.

(2) <u>Discussion</u>

We will adopt the budget for commercial, industrial, and agricultural efficiency incentives advocated by DRA. Several considerations are behind this decision.

First, PG&E's proposed levels of funding for the test year are identical to the expected expenditures for 1989. But spending on this program dropped considerably in 1989 compared to 1988. For most categories, even the much higher levels proposed by DRA are substantially lower than the average levels for these programs in the mid-1980s. For a number of reasons, we are persuaded that it is now appropriate to increase our emphasis on DSM programs. (The record of the en banc hearing of July 20, 1989, in I.86-10-001 provides a good exposition of the thinking behind our change in emphasis.) For the programs with the greatest differences between PG&E and DRA, DRA's recommendations are higher than recent levels of spending but lower than the levels of the mid-1980s. We believe that DRA recommends a reasonable and practical level for these programs, consistent with our goals for DSM programs.

Second, DRA's recommendations focus on the classes that have a great potential for improving efficiency and that face the highest rate increases. It is appropriate to emphasize DSM programs for agricultural and commercial customers. These customers face large rate increases because of our attempts to rationalize revenue allocation, and many of these customers have a limited ability to take advantage of available technologies for improving efficiency.

Third, efficiency improvements for industrial customers can help deter bypass by lowering the customer's energy bills. In I.86-10-001, we have encouraged utilities to explore efficiency improvements as an alternative to rate discounts as a way of retaining industrial customers with a potential to bypass the system. Energy efficiency incentives can supplement our efforts to deter uneconomical bypass.

We share TURN's concern that incentive programs should not be used to stimulate decisions that a rational company would make anyway. PG&E can tailor the incentive program to overcome TURN's concerns in various ways. For example, the program should focus on the smaller customers in each class who may not have the information or financial ability to make investments in efficiency. Also, PG&E should leverage the incentives in various ways to get the greatest energy savings for the least investment by ratepayers.

The adopted expenses for energy efficiency incentives is $20,124,000 for electricity and $882,000 for gas.

b. <u>Energy Management Services</u>

DRA agrees with PG&E's request for funding of the electric energy management services program, and PG&E now concurs with DRA's recommendations for the gas program. We will adopt the resulting budget of $7,583,000 for the electric energy management services and $2,542,000 for the gas portion of this program.

3. <u>Measurement and Evaluation</u>

CEC and DRA agree with PG&E's proposed budget for measurement and evaluation of DSM programs. The agreement of these parties includes an understanding that PG&E will work with DRA and CEC to define the scope of several studies that are part of PG&E's request. In addition, the parties understand that PG&E's annual contribution of $175,000 for an energy demand forecasting study is contingent on CEC's contributing $100,000 for the same purpose. (See Tr. 40:4414-4415.)

We will adopt PG&E's requested budget for evaluation and measurement of electric and gas DSM programs. The budget consists of $9,399,000 of expenses and $1,459,000 of capital investments for electricity, and $2,661,000 of expenses and $835,000 of capital investments for gas.

4. <u>Other DSM Expenses</u>

PG&E and DRA both allot $1,145,000 and $47,000 for other expenses of the electric and gas DSM programs. These expenses are for general administrative and support costs not directly attributable to specific DSM programs. We will adopt these amounts.

5. Load Retention and Load Building

a. Load Retention

The load retention program refers to activities like PG&E's efforts to defer or avoid uneconomic bypass projects, its negotiation of special contracts for electricity, its administration of unbundled gas tariffs, and its negotiation of gas transportation contracts. PG&E and DRA agree on a budget of $3,278,000 for electric programs and $1,406,000 for gas programs.

ERA argues that no funding should be allowed for load retention. ERA believes that PG&E has a need for capacity in 1990, and the Commission's decisions on special contracts state that these contracts should not extend into any period when a need for capacity exists. Thus, there is no logic to funding a load retention program at this time.

PG&E responds that ERA's recommendation is apparently based on its misunderstanding of what activities are covered by the load retention program. A primary component is the negotiation and approval process for special contracts, and ERA acknowledges that this activity is significant.

We will adopt the budget recommended by PG&E and DRA. These parties have proposed a reasonable budget for the expenses PG&E is likely to incur in negotiating special contracts, administering gas tariffs, and negotiating gas transportation contracts.

b. Load Building

PG&E requests funding for two load building programs.

The Area Development Program seeks to encourage existing industries to expand within PG&E's service territory and to attract new industrial and commercial customers into the area. The program is coordinated with California Department of Commerce and local economic development organizations. PG&E states that the program benefits customers by spreading fixed costs over a larger sales base. PG&E requests $1,522,000 and $694,000 for its electric and gas programs.

Valley Filling is a program to promote electric equipment that is used primarily in off- or partial-peak hours. For example, incentives are currently offered for security lighting. PG&E requests $1,100,000 for this program.

DRA opposes PG&E's load building programs. DRA's opposition is based on its concerns about long-term effects. PG&E's proposals are likely to result in long-term additions to load and increases in long-term costs. Funding these programs is inappropriate, in DRA's view.

CEC also opposes both programs. The programs may offer short-term rate benefits, but they are likely to cause significant costs in the long run. The programs may accelerate the need for new resource additions, and the Area Development Program could result in harm to the environment.

TURN and ERA also reject these programs. Programs that increase energy have no place in the conservation budget, according to these parties. ERA believes that PG&E faces a capacity shortage, and it is not logical to build load in the face of a capacity shortage.

We will authorize funding for the Area Development Program. Although we share many parties' concerns that this program could lead to increased costs in the long run, the program is part of a coordinated effort on the state and local level to stimulate economic growth in certain depressed areas. These economic benefits, in combination with the relatively small amount devoted to this program, outweigh our concerns about long-term costs.

However, we will make some adjustment to the amount authorized for this program. One of the functions served by this program, according to PG&E, is "encouraging potential customers to take advantage of PG&E's conservation and load management programs"

(Exhibit 11, p. 5). We believe that we have adopted funds for conservation and load management that will allow PG&E to promote its conservation and load management programs to all new and potential industrial customers, without a special authorization as part of this program. We will therefore reduce PG&E's request and authorize $1,000,000 and $500,000 for the electric and gas Area Development programs.

The Valley Filling program has no such countervailing economic benefits, and we will not grant PG&E's request for this program.

6. Load Management

a. Budget

PG&E requests $11,166,000 for expenses and $7,799,000 for capital-related expenditures for load management. DRA supports PG&E's request.

One load management program promotes Thermal Energy Storage (TES). TES chills water or other substances during off-peak periods for use in cooling during on-peak periods. PG&E's request for the TES program is $1,281,000.

CEC believes the TES program should be budgeted at $5,406,000. CEC argues that TES can improve load factors, shift usage from peak periods, and substitute for the Valley Filling program. The program also complements increased emphasis on TOU rates.

ERA recommends a budget of $2,000,000 for the TES program.

We will adopt PG&E's request for load management programs, including its recommendation for the TES program. We agree with CEC's points about the TES program, but it did not explain how it arrived at the budget it recommended for this program. PG&E may consider shifting funds to this program if circumstances justify such a reallocation.

b. TOU Installations

PG&E proposes to install install residential, commercial, and agricultural TOU meters at a rate of 20,000 meters per year. This rate is based on personnel limitations and on PG&E's estimates that the commercial and residential markets for TOU service will be saturated by 1996 and 1998.

DRA supports PG&E's proposed rate of installations. However, DRA believes the 20,000 meter rate should be considered a minimum and the market saturation dates should be viewed as goals for meeting the demand for TOU meters. DRA states that PG&E should continue to report its progress in its voluntary TOU program as part of its ECAC cases. If PG&E finds it needs to increase the rate of installation, the Commission should create some mechanism to allow PG&E to request increased resources. PG&E should file a marketing plan for meeting its goals, and should demonstrate on the date of saturation that all customers have been informed of their access to TOU options.

PG&E opposes DRA's restrictions. It believes the restrictions are based on the faulty premise that the primary purpose of TOU programs is load-shifting, and PG&E finds DRA's proposals unworkable or unnecessary.

Contra Costa first argues that PG&E's estimates of the number of customers who could benefit from TOU rates are too low. DRA's estimate is nearly twice as high, and even that estimate may be low. Contra Costa also disputes PG&E's approach to determining market saturation. PG&E thinks the market for TOU rates is saturated when 10% of the customers who could benefit convert to TOU schedules. Contra Costa believes a more appropriate saturation level is 33%. Contra Costa contends that a simple matter of following up on contacts about TOU rates is sufficient to increase the saturation level to the 33% it recommends.

Based on these recommendations, Contra Costa urges the Commission to set a goal of market saturation for residential customers within 10 years. At the rate of installation PG&E proposes, about 10,000 residential TOU meters per year, it would take 30 years to reach market saturation of the residential class.

Contra Costa concludes that the Commission should order PG&E to install 30,000 TOU meters for residential customers in each of the next three years. PG&E installed over 30,000 meters in 1987, so it is clear that it has the ability to meet this target. This goal should be firm and PG&E should not have the latitude to vary the pace of installation.

Contra Costa also thinks PG&E should market residential TOU rates when new customers call to request service.

PG&E disputes Contra Costa's points. First, PG&E notes that Contra Costa did not introduce evidence or present witnesses to support its arguments, and PG&E finds that many of Contra Costa's points are supported only by speculation. The difference between PG&E's and DRA's estimates of the number of customers who could benefit from TOU rates corresponds to differences in their recommended rate design for the residential class. PG&E's saturation rate of 10% is based on historical experience; Contra Costa's estimate of 33% is not based on facts. Installing 40,000 TOU meters per year would greatly increase PG&E's costs, and if Contra Costa's recommendations are adopted, the Commission should also increase PG&E's revenue requirement. Marketing TOU rates to new customers would be unwise because not all customers benefit from TOU rates, and PG&E is reluctant to market options that will increase customers' bills.

We will adopt PG&E's and DRA's installation goal of 20,000 TOU meters per year. We also support DRA's recommendation that PG&E should continue to report on the progress of the voluntary TOU program as part of its annual ECAC cases. PG&E appears to have responded well to the unanticipated increase in demand for agricultural TOU meters, and based on that experience we will not impose rigid requirements for the pace of installing TOU meters. We nevertheless are sympathetic with DRA's view that installing 20,000 TOU meters annually should be viewed as a minimum and that PG&E's estimated market saturation dates should be a goal, rather than merely an estimate. By the time of PG&E's next rate case, PG&E should have a well-developed plan for completing the saturation of the various markets for TOU meters.

7. Service Planning and Tariff Administration

PG&E requests $7,093,000 for electric Service Planning and Tariff Administration expenses and $3,957,000 for the corresponding gas expenses. These figures are an increase over current funding levels for these expenses, and PG&E believes changes in the number and complexity of these tariffs justify this increase.

DRA agrees with only half of PG&E's requested increase. DRA argues that there is no reason to believe that the rapid increase in individual contracts that has occurred in recent years will continue in 1990 and beyond. DRA thinks the administrative problems connected to these tariffs should stabilize, and that its proposed increase will be sufficient to meet customers' needs.

We will adopt DRA's recommended expenses of $6,579,000 for electric and $3,737,000 for gas Service Planning and Tariff Administration. We agree with DRA that many of the sources of additional work and expense in this area will stabilize over the next three years. Our adopted amounts still represent an increase over present levels of funding, and we believe that these amounts will be sufficient to meet increased activity in these areas.

D. Program Design Recommendations

In addition to its proposals for funding for DSM programs, DRA made several recommendations on the design and implementation of specific programs or groups of programs.

1. Shade Tree Promotion Incentives

DRA makes the specific proposal that PG&E should offer coupons as incentives for the purchase and planting of shade trees to reduce the need for summer cooling. Shade trees reduce the need for summer cooling in two ways. When they are planted next to buildings, they shelter the structure from the sun's rays. In addition, shade trees help dissipate "heat islands," which raise the temperature of urban areas several degrees during summer days and thus increase the demand for cooling.

DRA argues that a coupon with significant value to the customer provides a much more direct way of getting the customer's attention than an informational brochure. The coupon could be redeemed only for the purchase of deciduous trees of a certain height, so the effectiveness of the program would be improved. DRA also notes that its recommendation to increase the budget for the Conservation Information program assumed the existence of this program, and it would object to this increase if the coupon program is not authorized.

PG&E points out that because DRA classified the shade tree program as an information program, it did not perform a cost-effectiveness analysis for it. Thus, there is nothing in the record about how effective this program is. PG&E is willing to include information about shade trees, but it argues against actually funding purchases.

TURN supports DRA's proposal for additional funding for the Shade Tree program.

We will not specifically require PG&E to carry out the shade tree promotion as proposed by DRA. However, we agree that PG&E should vigorously promote the planting of shade trees in its service territory. A coupon program targeted to specific areas or groups of customers should be part of this program. In addition, we think PG&E should investigate working with logical groups--nurseries and nursery associations, local governments, garden clubs, and neighborhood associations, for example--who have interests other than energy conservation for encouraging tree planting. We encourage PG&E to take creative steps to magnify the effect of this program within the budget we have allowed. In addition, PG&E should attempt to measure the effectiveness of this program for our future evaluation of whether to continue or expand this program.

2. Appliance Efficiency Program

DRA initially recommended that more than two-thirds of the funding for this program should be devoted to promotion of compact fluorescent lighting and efficient refrigerators. In its opening brief, DRA modified its stance slightly and stated that other products could be emphasized provided similar load reductions resulted from comparable funding.

PG&E objects to DRA's proposed restrictions. It believes it should have the flexibility to create incentives for a mix of products.

CEC makes three recommendations for the design of the appliance efficiency programs. First, it recommends offering incentives to refrigerator dealers for selling efficient refrigerators. It supports its recommendation with references to a study that showed higher annual savings from this strategy than from direct incentives to consumers. Second, CEC proposes a rebate program for contractors to promote the installation of compact fluorescent lighting. Again, CEC believes that this step will greatly increase the cost-effectiveness of the program. Third, CEC thinks PG&E should expand its proposed program for high-efficiency air conditioners.

PG&E believes CEC's recommendations are based on limited, flawed studies and that no change to its programs is justified.

The point of DRA's proposal, as we understand it, is to increase the cost-effectiveness of the incentive program by emphasizing the most cost-effective products. We obviously agree that PG&E should seek to maximize the cost-effectiveness of its incentive programs. We recognize that PG&E needs some flexibility to test customers' reactions to other products, and that PG&E

criticizes the cost-effectiveness studies that are the basis for DRA's recommendations. We will not adopt the specific limitation proposed by DRA, but we note that efficient refrigeration has been an important part of this program in the past, and that compact fluorescent lighting is at a technical and economic level where it could make a substantial contribution to reducing the electricity consumption of lighting. CEC agrees that these devices deserve special emphasis.

We will also not restrict PG&E's programs in the way suggested by CEC, but we think CEC's proposals for leveraging the conservation investments deserve fuller investigation by PG&E.

E. Conclusion

Our adopted figures for DSM expenses and capital costs are shown in the following table:

Table 8

Authorized DSM Expenditures

Annual Average Program Costs
(1990-92; 1987 Dollars in Thousands)

	Electric Expenses	Electric Capital	Gas Expenses	Gas Capital
Conservation				
Res Information	$ 3,365	$ -	$ 1,307	$ -
Nres Information	694	-	150	-
Res EM Services	4,590	-	4,500	-
Comm EM Services	3,218	-	1,500	-
Industrial EM Services	2,529	-	902	-
Agric EM Servs.	1,836	-	141	-
Weatherization Retrofit Incentive	188	-	398	-
Appliance Effic Incentives	8,970	-	750	-
Comm EM Incentvs.	13,328	-	750	-
Industrial EM Incentives	5,796	-	44	-
Agric EM Incentvs.	1,000	-	88	-
Direct Assistance	17,636	-	13,291	-
Res New Constr.	3,036	-	248	-
Natural Gas Home			2,669	
Nonres New Construction	1,000	-	500	-
Total Conservation	$67,186	$ -	$27,238	$ -
Load Management				
Res A/C Cycling	239	396		
Interruptibles (C/I)	519	304		
Interruptibles (Ag)	290	26		

	Electric Expenses	Electric Capital	Gas Expenses	Gas Capital
Load Management				
Interruptibles (Grp Load)	342	38		
Thermal Energy Storage	1,278	3		
Industrial Load Shape	1,338	46		
Time-of-Use (Res & Nonres)	$ 6,842	$6,880		
Small Comm/Indst Project	154	19		
Real Time Pricing	-	-		
Demand Control Center	164	88		
Total Load Management	$11,166	$7,800		
Load Retention	3,278	-	$ 1,406	$ -
Load Building Area Devlpmt.	1,000		500	
Measurement & Evaluation	9,399	1,459	2,661	835
Other DSM	1,145	-	47	-
Total DSM	$93,174	$9,259	$31,852	$ 835
Service Planning & Tariff Adm.	6,579		3,737	
Total	$99,753	$9,259	$35,589	$ 835

DRA estimates that the conservation and load management budget we have adopted will result in first-year savings of 508 GWh and 69.7 MW of electricity and 7,572 million therms of gas (Exhibit 110, Appendix A). PG&E estimates that the load retention program will retain 826 GWh and 108 MW of demand (although losing an estimated 25 million therms of gas sales). PG&E also estimates that the Area Development program will add 100 GWh and 18 MW of electricity and one million therms of gas. We take these estimates to be fair representations of the effects that we may expect from our adopted DSM programs in the test year.

F. Disposition of Unspent DSM and RD&D Funds

We have previously established balancing accounts to record unspent DSM and RD&D funds. The account records the amounts that were authorized for these purposes, collected in rates, but not used by PG&E. On November 8, 1989, PG&E filed an advice letter requesting that a portion of the unspent DSM and RD&D funds from the 1987 rate case cycle be used to offset the rate increases resulting from this proceeding and PG&E's current ECAC case (A.89-04-001).

In a resolution considered at the same time as this decision, we approve PG&E's request. The rate increase that will take effect on January 1, 1990, will be reduced by $36,844,000 for electricity and $15,322,000 for gas.

Findings of Fact

1. On December 5, 1988, PG&E filed Application (A.) 88-12-005 to increase the gross revenues from base rates in effect on October 1, 1988, by $365,009,000, or 6.7%, for the Electrical Department and $125,056,000, or 5.1%, for the Gas Department. The total combined increase was $490,065,000, or 6.2%.

2. On March 22, we issued an order instituting Investigation (I.) 89-03-033 into the rates, charges and practices of PG&E. This order serves as the procedural vehicle for considering various recommendations that may go beyond the scope of the relief requested in A.88-12-005. This investigation was consolidated with A.88-12-005.

3. PG&E's final requested increase in revenues from CPUC-jurisdictional rates is $211,055,000 for the Electric Department and $74,756,000 for the Gas Department, for a total of $285,811,000. The requested increase in base revenues is $249,591,000 for the Electric Department and $74,756,000 for the Gas Department, a total of $324,347,000.

4. The issue of the proper level of payments to qualifying facilities for avoided operations and maintenance (O&M) costs was resolved in Decision (D.) 89-09-093, dated September 27, 1989.

5. In addition to more than 60 days of evidentiary hearings held in San Francisco, public participation hearings were held in Placerville, Eureka, Red Bluff, San Jose, and Fresno.

6. The foothills of the Sierra Nevada have cold winters, and many customers living there do not have gas service and are forced to heat with electricity.

7. PG&E serves an area where many people who do not speak English live.

8. An ALJ's ruling of April 24 consolidated the revenue allocation and rate design issues of A.89-04-001, PG&E's 1989 Energy Cost Adjustment Clause (ECAC) proceeding, with this general rate case.

9. An ALJ's ruling of May 24 determined that the ECAC sales forecast would be used in updated testimony on revenue allocation and rate design.

10. The ALJs' draft decision was issued November 16, 1989.

11. It is reasonable to use the ECAC sales forecast figure, issued in mid-August in ALJ Weissman's decision on resource assumptions in the PG&E ECAC proceeding (A.89-04-001), as the sales forecast in the general rate case proceeding to develop updated testimony on revenue allocation and rate design.

12. When faced with choosing between a more current forecast period and a longer, but older forecast period, the current forecast period is a more accurate forecast of anticipated revenue. It is reasonable to adopt DRA's forecast of $1,174,000 for Revenue Account 370.

13. It is reasonable to adopt DRA's updated revenue forecast of $361,000 in Account 371.

14. It is reasonable to expect an increase in Account 372 between 1987 and 1990 at the rate of inflation. Since the accounts covering rents paid by PG&E are escalated by the MSI index, it is reasonable to escalate similarly the rents received by PG&E.

15. PG&E and DRA are in agreement regarding the methodology to be used in developing labor and nonlabor escalation rates for the test year.

16. It is reasonable to adopt the agreed-upon labor escalation rate of 2.75% in 1988 and 1989, and 4.9% in 1990.

17. Applying the agreed upon methodology, it is reasonable to adopt non-labor escalation rates of 5.17% in 1988, 4.6% in 1989, and 4.83% in 1990.

18. If recorded expenses in an account have been relatively stable for three or more years, the 1987 recorded expenses is an appropriate base estimate for 1990.

19. If recorded expenses in an account have shown a trend in a certain direction over three or more years, the 1987 level is the

most recent point in the trend and is an appropriate base estimate for 1990.

20. For those accounts which have significant fluctuations in recorded expenses from year to year, or which are influenced by weather or other external forces beyond the control of the utility, an average of recorded expenses over a period of time (typically four years) is a reasonable base expense for 1990.

21. The expenses in the M&S component of Account 500 have declined steadily over the past four years; nor is there any indication of cyclic activity in recorded expenses since 1984. The trend is clearly downward, not cyclic. It is reasonable to adopt DRA's estimate for the M&S component of Account 500.

22. It is reasonable adopt DRA's estimate of the M&S component of Account 506 because the expenses in this account have declined steadily between 1985 and 1987.

23. The 1987 recorded expenses in Account 512.2 represent a reasonable midpoint between a possibility that the cycle in expenses may continue to decrease or may begin to increase by 1990.

24. It is reasonable to adopt DRA's estimate of the labor component of Account 512.3 because labor has trended downward in each year between 1985 and 1987.

25. In the absence of specific evidence regarding the added costs of increased maintenance in Account 513.5, an amount slightly above the four-year average of the labor expense will best represent expected costs in 1990.

26. DRA's estimate for M&S component of Account 546 is more reflective of expected activity in a very stable account for 1990.

27. It is reasonable to adopt PG&E's estimate for the M&S component of Account 548 because the M&S component has fluctuated significantly over the past four years.

28. The necessity for DRA's proposed adjustments to Accounts 514, 524, and 545.5 has not been adequately explained.

29. Where 1987 expenses are approximately equal to an average of several years, it is reasonable to use 1987 data as the base for Account 560.

30. PG&E has failed to demonstrate the necessity for a further increase in funding for line patrols in 1990.

31. The bare hand live-line training is a beneficial program. It is reasonable to adopt PG&E's revised estimate of $393,000 to reflect the changed extent of this program over three years.

32. PG&E's estimate is most representative of costs in Account 568 in 1990.

33. DRA removed substation expenses from Accounts 562 and 570 that it believes are associated with Diablo Canyon. PG&E's brief did not contest this adjustment.

34. Given that the 1987 labor expenses on Account 571.63 are approximately 50% higher than expenses in 1986 or 1988, 1987 expenses are not an accurate reflection of anticipated base workload in 1990.

35. In 1987 PG&E incurred only $37,000 for transmission pole treating.

36. As PG&E was previously authorized sufficient funds to test 133,000 distribution poles per year in 1987 through 1989, it is not reasonable to authorize additional funds for PG&E to test the previously funded "shortfall."

37. It is reasonable to adopt PG&E's estimate of the labor component of Account 571.74 because there is a three-year trend in increasing labor costs.

38. PG&E is negotiating with Edison for a share of the Pacific Interties High Voltage Direct Current (HVDC) Expansion Project.

39. The HVDC expansion project was a major issue in Edison's last general rate case. In D.87-12-066 we established a cost cap of $80 million for Edison's share of the HVDC expansion project, and we authorized Edison to file for an increase in the MAAC rate,

subject to refund, equal to 75% of the annualized investment related revenue requirement for the HVDC expansion after the project becomes commercially operational.

40. PG&E has not reached final agreement with Edison. The actual benefits will depend upon whether PG&E obtains an agreement with Edison, when the agreement is effective and upon the costs and terms specified in the final agreement. The projected costs of this project are too speculative to be included in the test year on a forecast basis. It is reasonable to authorize PG&E to recover these costs, subject to refund.

41. The labor and M&S components of five accounts, Accounts 583.2 (M&S and labor), 588 (M&S), 593.68 (M&S), 593.73 (M&S), and 594 (labor) have fluctuated significantly over the past four years (1985-87), with no discernible trend. Absent a specific explanation of why 1987 recorded data best reflects the estimated 1990 expenses of an account with fluctuating expense levels and no discernible trends, it is most appropriate to use a four-year average as the base 1990 estimate.

42. The labor component of Accounts 582 and 583.30 has steadily declined over the past four years. While we will not project further declines in the test year, neither PG&E nor DRA has explained why the 1987 recorded estimate should be adjusted upward.

43. PG&E's update exhibit requests an increase of $1,159,000 in electric account 588 and $479,000 in gas account 880, to cover the costs of new safety requirements imposed by the California Motor Vehicle Act of 1988.

44. The requirement of a daily inspection was not a change mandated by the 1988 Act.

45. PG&E's witness had not looked into existing inspection procedures to determine whether the required 45-day inspection is compatible with PG&E's existing inspection requirements.

46. Despite the availability of a procedure to avoid or minimize inspection procedures which PG&E believes are unnecessary

and unproductive, PG&E has not requested a different inspection interval than that provided by statute.

47. PG&E has not met its burden of proof in support of the requested increase for motor vehicle inspections.

48. Where FEA alleged a computational error in Account 592 and explained how it traced the error, PG&E did not provide explicit explanation of why it believed no error was made.

49. When the tree replacement program is scaled up to a rate of 6,500 trees per year, it is reasonable to expect significant savings and efficiencies from the costs incurred under the pilot program. It is reasonable to authorize PG&E $3,000,000 to replace a minimum of 6,500 trees per year.

50. The phased rewrite of the CIS system is a reasonable approach to correcting the difficulties, limitations, and inefficiencies of a system which is nearing the end of its useful life.

51. The fact PG&E has made a more conservative request than the amount shown in the study is not a legitimate reason for rejecting funding for the project. PG&E has made a conservative request and has committed to meet the additional costs from its own resources.

52. PG&E's test year estimate (which will be carried forward to the attrition years), together with the DH&S estimate of incremental costs in 1993-95, is the maximum amount ratepayers should be expected to contribute to this project.

53. PG&E requested authorization to revise Electric and Gas Rules 9 and 11 to include field collection and reconnection charges. DRA concurred in this recommendation after simplifying the proposed charges. PG&E is authorized to include revisions to these Rules in the revised tariffs as set forth in this decision.

54. PG&E reviewed the Electric Plant Accounts to exclude $5.778 billion in Diablo Canyon direct plant costs.

55. PG&E reviewed its Nuclear Production O&M accounts, and removed $145,667,000 in base year 1987 expenses that historically have been directly charged to Diablo Canyon.

56. PG&E made adjustments for Administrative and General Expenses. According to PG&E, the total exclusion of Diablo Canyon related A&G is $65.2 million.

57. PG&E identified an additional $5,000,000 in Diablo Canyon's expenses reflecting charges and rentals attributable to the use of common plant, such as vehicles, aircraft, and the general office complex, by Diablo employees.

58. In its report on the Segregation of Costs for Diablo Canyon, the DRA stated that the most accurate method for segregation of costs would be a properly performed use study.

59. The use of "gross plant" in DRA's proposed special four-factor method seriously overstates Diablo Canyon's impact on A&G costs.

60. The use of generating capacity and annual energy output in DRA's special four factor weigh the allocation too heavily toward the size of the facility, such that the use of both amounts to double counting.

61. The use of "annual energy output" in DRA's four factor is defective when the plant is not operating.

62. Three of the four factors in DRA's allocation do not bear a reasonable relationship to the costs to be allocated and are not a reliable means of estimating A&G expenses resulting from operation and maintenance of Diablo Canyon.

63. PG&E and DRA's auditors agree that $27.8 million in expenses charged to Diablo O&M "typically" would be categorized as A&G expenses. PG&E also reviewed its A&G costs and directly removed $26,563,000 from base year 1987.

64. PG&E removed $9,990,000 in peripheral A&G. Although these costs were associated with several A&G accounts, PG&E deducted the total amount from Account 921.

65. PG&E's estimate of peripheral A&G expenses is based upon an informal survey of various administrative departments conducted by PG&E in the fall of 1985.

66. The use study did not survey all executives, departments and operations which would be expected to incur costs associated with Diablo Canyon. Although senior PG&E officers book their salaries to a subaccount of Account 920, none of the time or expenses of the president which related to Diablo Canyon was allocated through this study of peripheral costs. None of the time of the Board of Directors was allocated by PG&E to Diablo Canyon.

67. Not all costs of running the company may properly be charged to ratepayers as cost of service.

68. The company's three 1989 initiatives are to operate the utility in such a manner as to earn the full authorized rate of return; to operate Diablo Canyon safely, reliably and profitably; and to invest in suitable unregulated businesses.

69. Only those expenses incurred in the first of the company's initiatives, operation of the utility, are properly a cost of service to be charged to ratepayers.

70. There is very little evidence in this record regarding the amount of actual time and expenses of corporate center personnel currently devote to Diablo Canyon activities. The limited information that is available suggests that the estimates of expenses which were made in 1985 will not accurately reflect the actual allocation of costs to Diablo Canyon in 1990.

71. In the absence of records to reflect how the 1985 estimates were derived, it is not reasonable to rely on PG&E's use study as a basis for segregating common costs.

72. The cost of preparing an income tax statement for revenues derived from Diablo Canyon is clearly a cost of owning and operating the facility and is a cost, for ratemaking purposes, which must be fully segregated from other PG&E operations.

73. No cost is more clearly a cost of owning and operating Diablo Canyon that the cost of identifying expenses to be charged to Diablo Canyon.

74. PG&E's study of peripheral costs is unreliable, because it was informal, limited in scope, and poorly documented.

75. Other than direct assignment, the most accurate and preferable method of satisfying the requirement of D.88-12-095 that the common costs of Diablo Canyon be fully segregated, is for PG&E to conduct a current, full-scale use study of expenses booked to Administrative and General Accounts, and to carefully and completely allocate such expenses between Diablo Canyon and other operations.

76. For four accounts (923, 924, 925, and 930.2), it is reasonable to accept PG&E's allocation of Diablo Canyon expenses on an interim basis.

77. For eight A&G accounts, the amounts allocated by PG&E to Diablo Canyon, if any, are likely to significantly understate the full extent of A&G costs resulting from Diablo Canyon operation.

78. A&G Account 920 has historically reflected a causal correlation with overall labor expenses. Therefore, it is reasonable on an interim basis to remove 16% of the total A&G expenses as the amount we reasonably expect to be chargeable to Diablo Canyon operations.

79. Account 921 includes office supplies and expenses attributable to specific administrative and general departments. We would reasonably expect that the percentage of office supplies and expenses related to Diablo Canyon would correlate with the ratio of Diablo Canyon labor to total company labor. Therefore, it is reasonable on an interim basis to remove 16% of the expenses attributed to this account as the amount we reasonably expect to be chargeable to Diablo Canyon operations.

80. PG&E's formula for calculating Diablo Canyon pension expense is likely to misstate the actual costs, unless there is a

constant relationship between the cost of the Diablo Canyon labor expense and the total company labor expense between 1987 and 1990. A constant relationship is unlikely.

81. Account 928 includes expenses incurred by the utility in connection with cases before regulatory commissions. PG&E has removed $16,000 from this account for which it will be credited. Diablo Canyon related costs should represent at least 16% of the total expenses in Account 928. Therefore, it is reasonable on an interim basis to remove 16% of the expenses attributed to this account as the amount we reasonably expect to be chargeable to Diablo Canyon operations.

82. TURN recommends reducing PG&E's RD&D budget by $1,111,000 to account for four projects that are intended to provide specific benefits to Diablo Canyon.

83. PG&E does not deny a causal link between Diablo Canyon and RD&D expenses.

84. A portion of the EPRI budget relates to the operation and maintenance of existing nuclear power plants. Diablo Canyon will be able to share and use PG&E's EPRI information.

85. If Diablo Canyon utilizes the resources of the utility, that utilization incurs a cost and the cost is a cost resulting from the operation of Diablo Canyon.

86. Account 931 includes rents for property used by the utility for general and administrative functions. PG&E attributes $1,722,000 to Diablo Canyon in this account for which it will be credited. We would expect that the percentage of this account attributable to Diablo Canyon would approximate the ratio of Diablo Canyon labor to total company labor. Therefore, it is reasonable on an interim basis to remove 16% of the expenses attributed to this account as the amount we reasonably expect to be chargeable to Diablo Canyon operations.

87. Account 935 includes administrative and general expenses incurred in the maintenance of property. It does not appear that

PG&E's system of direct charging provides for reimbursement of Account 935 expenses. In the absence of such evidence, an adjustment is appropriate for Diablo Canyon related costs. We will use the 16% adjustment used for Accounts 920 and 921. Therefore, it is reasonable on an interim basis to remove 16% of the expenses attributed to this account as the amount we reasonably expect to be chargeable to Diablo Canyon operations.

88. PG&E proposes a new management incentive plan. The new plan merges and expands PG&E's previous management incentive and team award programs. PG&E originally requested $19,981,000 for funding the MIP. PG&E later reduced this amount by $1,775,000, associated with the Nuclear Power Generation unit, resulting in a revised request of $18,116,000.

89. The previous MIP included approximately 160 employees, including the Chairman, the President, and the uppermost officers. The new MIP includes all PG&E exempt employees, approximately 7,000 in number.

90. There is already adequate revenue to fund the new MIP. PG&E has launched the new MIP in 1989 and is capable of funding the program, either within the currently authorized labor expense, from currently achieved savings in other accounts or from the benefits derived by shareholders from increased efficiency.

91. PG&E has not offered any evidence that base pay for management employees will be at or below market levels in 1990. As long as PG&E's management salaries falls within 10% of the survey median, as it does in this case, such salaries should be considered to be competitive.

92. PG&E has not quantified the savings which will result from the expanded MIP. The target goals of the MIP were developed and distributed to employees for 1989 long after the application was prepared and filed. Goals for 1990 have still not been set. PG&E's evidence fails to demonstrate to us that greater savings or

efficiencies will result with the MIP in the test year than without it.

93. There is no direct financial benefit to ratepayers from PG&E meeting its target goal under the MIP. Ratepayers will indirectly benefit in the long run from vigorous cost containment and cost reduction by utility management, but the relative benefits under PG&E's scheme are so overwhelmingly weighted in favor of shareholders, it would not be just or reasonable to require ratepayer contribution above the amounts otherwise authorized for base pay in this decision.

94. Corporate ROE, a primary goal of the MIP, is based in part on the the performance of Diablo Canyon and PG&E's unregulated subsidiaries. It is inappropriate for ratepayers to underwrite incentives based on the performance, cost, or quality of service of PG&E's non-utility or Diablo Canyon operations.

95. The FERC Uniform System of Accounts requires that account information be maintained so as to permit ready summarization according to the nature of the service and the person furnishing it. PG&E took six months to provide information which should have been readily summarized in account level detail.

96. As a consequence of PG&E's delay in providing an accounting of Account 923, we cannot conclude that 1987 recorded expenses form a reasonable basis for estimating expenses in the test year.

97. PG&E's estimate for Account 925 in 1990 is $37,843,000. This estimate is slightly higher than inflation. While PG&E has been successful in controlling the growth of third party liability to just over 8% between 1985 and 1988, PG&E does not believe that will continue.

98. It is reasonable to adopt PG&E's estimate of expenses for Account 925, as agreed to by DRA, and amortize the 1990 Carmen settlement payment over three years.

99. It is premature to begin funding of a 401(h) program in anticipation of a FASB standard that has not yet been finalized. It is possible that the methods of expensing post-retirement medical benefits may differ materially from those proposed in the FASB exposure draft.

100. Given the magnitude of the potential unfunded liability and the relatively minor contribution PG&E proposes to make over the next three years there is no harm to ratepayers or to PG&E's financial statements by deferring a decision on prefunding until the new FASB standard has been finalized.

101. DRA has offered no new facts or circumstances which would warrant reconsideration of D.88-03-072. It is reasonable for PG&E to use a "contribution approach" to calculating pension costs in the test year.

102. For 1988, it is preferable to utilize actual recorded medical expenses, rather than PG&E's estimate of such expenses.

103. For 1989, the premium and accrual rates for PG&E's HMO and indemnity plans are likely to be a very accurate estimate of medical expenses to be incurred in 1989.

104. A simple arithmetic average of the percentage increases in indemnity plan costs over the last 4 years shows a 9.2% increase. It is reasonable to adopt an estimate of medical expenses in 1990 which is 9.5% above the 1989 estimate.

105. PG&E has not met its burden of proof of explaining how the adjustments for "current medical cost factors" were derived and why they are not reflected in current trends.

106. PG&E's contribution to PSEA is, in part, a charitable contribution to a association for the furtherance of charitable, educational and social activities.

107. The NARUC audit provides us with sufficient information to make an informed evaluation of the expenses which are appropriate for rate recovery. DRA's proposed disallowance of EEI dues is supported by the audit.

108. The anticipated decrease in leased space in 1991 and 1992 results from PG&E's continued effort to consolidate working groups and use office space more efficiently. This is the type of improved efficiency we expect to see during the attrition years; these savings should help to offset other increased costs not authorized in the test year.

109. In reference to PG&E's proposal to amortize the cost of certain abandoned plant, PG&E has not shown (1) that the project ran its course during a period of unusual and protracted uncertainty, (2) that the project was reasonable throughout the project's duration in light of both the relevant uncertainties that then existed and of the alternatives for meeting the service needs of the customers, (3) when the projects were cancelled, and (4) that they were cancelled promptly when conditions warranted.

110. None of PG&E's reasons for canceling the abandoned projects falls within the narrow exception to the "used and useful" rule of D.84-05-100.

111. The purpose of the PHFU guidelines is to balance the utility's natural desire for maximum possible flexibility in the planning and acquisition of future plant with the ratepayer's desire to avoid unnecessary or burdensome carrying costs of property which is held for an indefinite period or an indefinite purpose.

112. It is reasonable to provide a longer holding period for power plants and related transmission facilities than for transmission facilities only.

113. Application of the PHFU guidelines to the Gates-Gregg project is fully warranted.

114. PG&E has neither shown a definite plan and need, nor an economic analysis to justify retention of the Pittsburg properties in PHFU.

115. PG&E states that it has removed from rate base $134,000,000 of plant within the gates of the Diablo Canyon

facility and used by Diablo Canyon, which would ordinarily be classified as as "common plant".

116. PG&E identified $5,000,000 in Diablo related expense, reflecting charges and rentals attributable to the use by Diablo Canyon employees of vehicles, aircraft and the General Office complex.

117. DRA noted in its testimony that a comprehensive use study is the most accurate method for segregating Diablo Canyon costs. Neither DRA nor PG&E has advanced an acceptable method for fairly and accurately allocating the costs of plant shared between Diablo Canyon and other departments of PG&E. DRA's method is likely to overstate the costs of common plant attributable to Diablo Canyon. PG&E's proposed charge of $5,000,000 is likely to understate the costs incurred by Diablo Canyon for the use of shared facilities outside the gates of Diablo Canyon.

Therefore, it is reasonable to accept PG&E's estimate of common plant on an interim basis. PG&E has provided DRA adequate time to review the San Francisco Division Consolidation and Emeryville projects and PG&E has demonstrated that both projects will be used and useful in 1990.

118. DRA and PG&E agree on the methodology for calculating depreciation and depreciation reserve.

119. DRA and PG&E also agree on the methodology for calculating income, payroll, property and other tax expense.

120. Based on PG&E's most recent estimate of the costs of decommissioning Diablo Canyon, PG&E would need to collect $52,015,000 annually, beginning in 1990. This is $2,459,000 less than PG&E is currently collecting.

121. There are significant future uncertainties concerning the timing of decommissioning, the amount ultimately necessary to complete the work, and the rate at which the trust will appreciate over the next three decades. Given the range of future uncertainty, minor fluctuations between the authorized accrual

rates and the most recently forecasted rate of accrual are not a matter of immediate concern.

122. The DRA salary survey suffers some of the same errors and limitations as noted by the Commission in the 1987 general rate case. DRA's survey also fails to contain the further refinements we requested in D.87-12-066. DRA's survey does not make a comparison on a total compensation basis. DRA continues to provide point comparisons based on averages, without also indicating the range of data. DRA was even less aware of which companies participated in the surveys it used.

123. The inference of PG&E's testimony is that it is less costly to translate PG&E account numbers to FERC account numbers than to incorporate the information directly into the accounting system.

124. The recorded 1987 expenses do not fully reflect the full benefit of the reductions achieved from PG&E's major workforce reduction by the end of 1987.

125. The results of the productivity model do not foreclose an otherwise reasonable adjustment to the PG&E accounts reflecting labor expenses in the test year.

126. DRA proposes an adjustment of $3,644,000 for gains on sale of property. PG&E did not offer testimony in rebuttal to DRA's proposed adjustment.

127. Our practice in Edison's recent general rate proceeding, for property originating in Accounts 101 and 103 and transferred to Account 121 prior to sale, was to allocate the gains between shareholders and ratepayers based upon the time the property was in rate base.

128. A.87-07-041 is not a generic investigation. It is a proceeding focusing on a specific financial transaction involving one utility. That utility is not PG&E.

129. The purpose of the internal corrosion program is to provide information regarding the integrity of the gas collection

system and to identify additional corrosion mitigation measures. PG&E acknowledges that the number of pumps, probes and dehydrators to be installed cannot be determined until further evaluation is made. PG&E's witness did not have personal knowledge of the status of the testing program.

130. PG&E's request of $2,000,000 per year for the McDonald Island Levee Repair is reasonable.

131. PG&E has not clearly articulated why its estimate of the Pipeline Replacement Program expenses based on a "job estimate" ratio is a more accurate predictor than a ratio based on recorded expenses. In particular, PG&E has failed to explain how its estimate accounts for both the increase in San Francisco work and the systemwide decrease in miles of main and service replacements. PG&E has not met its burden of demonstrating the need for its requested increase in M&O expenses.

132. DRA's disallowance reasonably approximates the portion of the AGA dues attributable to lobbying, contributions and advertising.

133. PG&E's experts have not satisfactorily reconciled PG&E's decision to defer major gas meter installations in 1989 with its decision to accelerate the schedule in 1990. The schedule originally proposed by PG&E to install 12 meters in the first year of the program is a reasonable basis for funding this project in the test year. It would be poor planning and unfair to the ratepayers to authorize funding for more gas meters than may be needed or for more gas meters than can be installed in the test year.

134. PG&E has not explained why it is reasonable to proceed with the operational phase of the residential automated meter program before it completes its technological assessment of the five meter types.

135. The meter protection program is new and specific priorities and details will be worked out in conjunction with the

Commission's Safety Division. It is reasonable to approve $4,958,000 for the first year of this program.

136. The capital cost of new plant should be recorded when it becomes operational. In this instance, PG&E does not explain why five projects which were operational in 1987 could not be included in an estimate of 1988 plant prepared in the spring of 1988. Nor were these projects listed in the update to the NOI, which was filed with the application in December 1988.

137. PG&E had more than sufficient time to include plant placed in service in 1987 in its 1988 estimate of plant additions. Under these circumstances, it is not reasonable to include these projects in the test year estimate.

138. Miscellaneous abandoned gas projects under $100,000 each are not listed or otherwise identified in PG&E's testimony. PG&E does not explain how these projects meet the Commission's criteria.

139. In A.86-12-095 we authorized $2,000,000 per year for investigations and program development, including ongoing investigations of manufactured gas plant sites at a rate of at least ten sites per year.

140. PG&E has only eight sites under active investigation, will initiate investigations at three sites in 1989 and anticipates investigations at three new sites per year thereafter. Although we authorized $2,000,000 per year for hazardous waste site investigations, PG&E spent an average of only $1,250,000 on site investigations in 1987 and 1988.

141. Ratepayers have already funded the investigation of 30 sites in the last rate case cycle. PG&E has not used all of the money previously provided for this purpose.

142. Having found in both D.86-12-095 and D.88-09-020 that it is appropriate for PG&E to recover underground tank clean up expenses in base rates, there is no need to revisit the issue again in this proceeding.

143. In 1987 1,313 W/MBE firms received $102.7 million of business with PG&E, representing 8.8% of total corporate expenditures. In 1988, W/MBE firm received $152.6 million of work, or 12.2% of corporate expenditures. PG&E has significantly exceeded its short-term goals of 6% participation by minority-owned enterprises and 5% participation by women-owned enterprises.

144. PG&E's estimated cost in establishing and maintaining the W/MBE central clearinghouse of approximately $756,000 (1990 $) for the 1990 calendar year is reasonable.

145. DRA conducted a limited review of the general structure and financial relationship between Enterprises and PG&E.

146. PG&E currently applies its Standard Practice 117.1 for billings to third parties to transactions with Enterprises, including overheads of 20% for nonproductive time, 29% for payroll taxes, 14.37% for insurance and casualty loss, and 26.84% for A&G labor payroll additives and general office supplies and miscellaneous expense.

147. DRA recommends that the Commission adopt comprehensive guidelines governing intercompany transactions. DRA asks that the Commission order PG&E and DRA to jointly develop these guidelines using the guidelines in D.88-01-063 as a basis.

148. PG&E's rebuttal testimony did not specifically address DRA's recommendation that the Commission adopt comprehensive guidelines governing intercompany transactions, but in its Reply Brief, PG&E proposes eight guidelines for Commission adoption.

149. TURN recommends an audit to comprehensively evaluate the relationship between PG&E and Enterprises.

150. Because PG&E's witness O'Flanagan was not directly involved with Enterprises and because of his limited review of its operations, his testimony failed to fully explain the nature and scope of intercompany transaction, much less demonstrate conclusively why they are reasonable.

151. There is insufficient evidence on this record for us to determine the proper allocation of costs between PG&E and Enterprises in 1990 or for us to adopt, at this time, guidelines relating to such allocation.

152. DRA has not presented an adequate factual or analytical foundation to support its proposed capital related productivity adjustment.

153. It is proper to amortize nonrecurring expenses which are incurred in the test year over the three-year rate case cycle. While PG&E may incur unforeseen expenses in attrition years, overcollection for nonrecurring test year expenses is not an appropriate source of revenue to fund these increases. Additional productivity and management acumen will offset activity growth, customer growth and new mandated programs during the attrition years.

154. PG&E and DRA largely agree on the basic RD&D budget presented in Exhibit 13-B.

155. TURN recommends reducing PG&E's RD&D budget by $1,930,000 to reflect the cost of research designed to benefit Enterprises.

156. PG&E's resource plan is intended to be a least-cost plan with additions tested for cost-effectiveness. The purpose of DRA's resource plan is primarily to test the cost-effectiveness of demand-side management programs.

157. For its long-term resource plan, PG&E developed its own load forecast for the test year with increasing reliance on the CEC's ER-7 demand forecast until the forecasts for 1995 and beyond are entirely derived from ER-7.

158. PG&E's natural gas demand forecast is based on material filed in the 1988 California Gas Report.

159. In an attempt to narrow the disputes about production cost models, we have developed procedures to help the parties isolate the real differences between them.

160. The CEC has determined that the planning assumptions of ER-7 should take 500 MW of spot capacity into account.

161. In ER-7, the CEC determined that firm capacity would amount to 705 MW in the test year, declining to 215 MW by 2007, for PG&E's service area.

162. For PG&E's service area, the CEC identifies pending resources total -39 MW for the test year, increasing to 500 MW by 1994.

163. The California-Oregon Transmission Project (COTP) is proposed as a joint project of several municipal and investor-owned utilities.

164. The CEC in ER-7 includes 848 MW of the municipal utilities' portion of COTP.

165. Northwest power will be cheaper when it is more plentiful, and more expensive when there is greater demand for it.

166. PG&E assumes that the Northwest Intertie will be fully loaded with contracted firm capacity and purchased spot capacity both for the test year and in the long term.

167. PG&E includes sales from Pacific Power and Light to SMUD in its estimates of surplus energy available from the Northwest.

168. PG&E performed its own analysis of expected capacity from QFs and self-generation, rather than relying on the CEC's figures. DRA relied on an analysis prepared by a consultant to the CEC.

169. PG&E's long-term resource plan for this proceeding includes 2,700 MW of generic additions of baseload resources by 2007.

170. DRA derated the Helms facility by 395 MW because of the plant's poor reliability record during past peak periods. Equipment that will permit peak operation of all three units at the Helms plant has been installed.

171. PG&E includes in its resource plan 167 MW of upgrades associated with relicensing of its hydroelectric facilities.

172. In June 1989, voters decided not to allow SMUD to operate the Rancho Seco nuclear power plant.

173. SMUD has capacity contracts with both PG&E and Edison that could be drawn on in the short term to replace Rancho Seco's capacity.

174. DRA has recommended higher levels of DSM funding than those underlying the CEC's recommendations in ER-7 on the level of uncommitted DSM.

175. DRA prices as-available QFs at the marginal costs generated by the ELFIN simulations.

176. DRA's projections of fuel prices show a convergence of the dispatch price and average price of gas.

177. DRA's forecasted average gas prices appear to be more reasonable than PG&E's.

178. DRA recommends procedures to follow when results of production cost models are in issue.

179. DRA uses four blocks to model the capacity of the Diablo Canyon nuclear power plant. DRA's approach is consistent with the data from CEC's common forecasting methodology (CFM) proceeding.

180. In its modeling, DRA uses PG&E's load shapes for 1990, but relies on the load shapes used by the CEC in ER-7 for later years.

181. PG&E includes all of Helms' capacity in arriving at its spinning reserve requirements.

182. DRA derives dispatch costs for gas-fired units, and uses production costs for dispatch purposes for all other types of generation.

183. Calculation of the ERI compares the utility's target reserve margin with the reserve margin resulting from forecasts of the utility's demand and resources for individual years.

184. In calculating the ERI, all concerned parties agreed to use the demand forecast developed by the CEC for ER-7.

185. The parties agree that the CEC's adopted target reserve margin of 17.5% should be used to calculate the ERI.

186. D.89-06-048 adopted a formula for calculation of the ERI that differs slightly from the one PG&E and DRA used in their original testimony.

187. D.89-06-048 chose an exponential, rather than a linear, formula, adopted a floor value of 0.4, and required use of the target reserve margin the CEC adopted in ER-7.

188. Use of the 17.5% target reserve margin of ER-7 and the associated "age-derating" of capacity from oil- and gas-fired generating plants reduces the capacity of these plants in PG&E's service area by a cumulative total of 489 MW by 1992.

189. The determinations of this decision result in the ERIs shown in Appendix H. The average for the six years beginning with the test year is 0.418.

190. DRA recommends adjusting marginal capacity and customer costs for franchise fees and uncollectibles (FF&U).

191. TURN points out that the general plant loading factor (GPLF) used by PG&E improperly included costs related to gas distribution.

192. PG&E and DRA agree that use of the annualized cost of a combustion turbine results in an estimate of marginal generation capacity costs of $55.69/kW-yr.

193. The ERI was originally developed as a way to adjust the capacity prices paid to QFs to reflect the value of the additional capacity supplied by QFs to the utility's system. The ERI was developed to offer a way of reflecting the value of additional capacity to the system over a range of relationships between resources and demand.

194. Taking the six-year average ERI suggested by DRA for use in revenue allocation and rate design provides not only rate stability, but also a reasonable balance between long-run and

short-run assessments of the need for and cost of generation capacity.

195. DRA agrees with PG&E's basic estimate of marginal transmission capacity costs of $32.19/kW-yr., adjusted for franchise fees and uncollectibles.

196. The distribution system performs both a capacity or demand-related function and a customer access function.

197. DRA and TURN agree with PG&E's final estimate of marginal primary distribution capacity costs of $52.54/kW-yr.

198. PG&E believes marginal secondary distribution costs have a demand-related component that should be reflected in marginal capacity costs. PG&E calculates this demand-related cost to be $6.81/kW-yr.

199. Marginal secondary distribution capacity costs can be viewed as a measure of variance, of the extent to which planning secondary distribution circuits on the basis of averages results in some undersized circuits.

200. TURN pointed out that the estimates of customer accounts and collections costs related to marginal customer costs included three different errors totaling about $16.5 million.

201. In calculating marginal customer costs for the residential, agricultural, and small light and power classes, DRA adds a 3% vacancy factor to customer-related investments.

202. DRA and PG&E agree that marginal customer costs should reflect the characteristics of typical installations in the standing stock of existing installations for the residential, agricultural, and small light and power customer classes.

203. PG&E's estimates of the marginal customer costs for the medium light and power class and the primary and secondary level of Schedules E-19 and E-20 are consistent with our decision to allocate the bulk of secondary distribution O&M costs to marginal customer costs.

204. PG&E based its estimate of transmission level customer costs for Schedules E-19 and E-20 on recorded data from 26 job estimates of transmission level customer connections. Other parties objected to the inclusion of the cost of dedicated line extensions as not reflecting the costs of providing access to typical customers.

205. DRA believes that certain costs common to all streetlighting customers should be treated as customer-related.

206. The customer accounting costs developed in the streetlight facility cost study are more accurate than those used by DRA.

207. PG&E's preferred model is PROMOD 27.9; DRA prefers ELFIN 1.7.

208. TURN argues that using only the commodity cost understates the true cost of gas and the resulting marginal energy costs.

209. TURN proposes that the marginal energy cost calculation should reflect the cost to society of the oxides of nitrogen (NOx) produced by power plants that burn fossil fuels.

210. PG&E proposes to split the existing large light and power class into two new classes. The new E-20 class is for customers with maximum demands of 1000 kW or more and includes Schedules E-20, E-24, E-25, A-RTP-20, S, and special contracts with large customers. The new class E-19 covers customers with maximum demands of 500 to 1000 kW and includes Schedules E-19, A-RTP-19, and S.

211. PG&E agrees with DRA's recommendations on calculation of class coincident demands.

212. Many factors, other than daily cycling, can affect O&M costs.

213. For the residential and small light and power classes, the final line transformer typically serves more than two customers.

214. A single agricultural customer can have multiple accounts, and the diversity of the accounts is accurately reflected by measurements of maximum demand at the final line transformer.

215. A new generating plant may be more reliable than the existing mix of resources and may permit a decrease in the target reserve margin.

216. When a utility's actual reserve margin is well above its target reserve margin, an increase in demand does not require any addition to reserves.

217. In this case, all parties endorse the EPMC approach to interclass revenue allocation with limits (caps and floors) to moderate the rate effects on particular classes.

217a. The agricultural class is still in the midst of a widespread conversion to TOU rates, and it is reasonable to expect that TOU will change the usage characteristics of this class.

218. Revenues from special contracts often differ from the revenues that would be collected if customers with special contracts were served under the appropriate tariffs.

219. Removing all sales and revenues associated with special contracts from the allocation process leaves the relationships among the other classes unaltered.

220. In PG&E's last general rate case we distinguished between revenues from tariff rates that recover the types of costs that are included in the revenue allocation (allocated revenues) and revenues that reflect other types of costs or savings (nonallocated revenues).

221. Schedule AG-5 applies to a large group of customers, with many varying circumstances.

222. The rate for Schedule AG-5 is close to marginal cost.

223. The agricultural class has a greater fluctuation in sales than other classes.

224. Generation reliability problems affect all customers equally, not just rural customers.

225. PG&E and DRA differ in their estimates of the usage characteristics and number of customers on the new residential TOU schedules. DRA refined a number of PG&E's assumptions.

226. Customer acceptance is a consideration that should outweigh economic correctness in evaluating the customer charge.

227. PG&E proposes a reduction of the differential between Tier 1 and Tier 2 residential rates by 50%. DRA proposes a tier differential reduction of 10%.

228. PG&E and DRA agree on four principles for the calculation of baseline quantities. First, baseline quantities should be established at the maximum allowed under Public Utilities Code § 739. Second, four years of billing data should be used to calculate the target quantities in this case. Third, in the next general rate case, temperature-adjusted data should be used instead of multi-year averages. Fourth, target quantities for master-metered dwelling units should be set by reducing the corresponding individually metered quantity by the ratio of master-metered usage to average individually metered usage by end-use, season, and climate zone.

229. If the minimum bill were not reduced by 15%, the LIRA discount would be lost to low-income customers who consume less than the amount allowed by the minimum bill.

230. Schedule OL-1 provides outdoor lighting for customers other than governmental entities.

231. PG&E thinks the summer on-peak to off-peak ratio for Schedule E-7's rates should be set at 80% of the full EPMC level. DRA believes that all pertinent rate differentials should move halfway from current relationships to EPMC-based differentials. TURN proposes a revenue-neutral on-peak rate.

232. PG&E proposes a new Schedule E-8 with a customer charge based on full EPMC, seasonally differentiated energy charges, and no baseline credit.

233. DRA proposes a new Schedule E-9 that resembles Schedule E-7. However, the new schedule would have a customer charge based on full EPMC, energy rates derived from EPMC-based seasonal and TOU differentials, and no baseline discount.

234. DRA has projected that Schedule E-9 will attract only 1,490 customers in 1990.

235. PG&E conducted new cost studies and developed its proposed master-meter discounts from them.

236. Over 36% of the Schedule ET bills had average rates that were less than or equal to the ECAC rate, and 27% of the Schedule GT bills had average rates that were less than or equal to the core weighted average cost of gas (WACOG) rates.

237. PG&E uses a vacancy factor to reduce the component of the master-meter discount associated with customer accounts. WMA applies the vacancy factor to the investment the master-meter customer has made in the equipment that provides service to the tenants.

238. The master-meter customer could benefit unfairly from the diversity of tenants' consumption patterns by purchasing some power at Tier 1 rates and reselling it at Tier 2 rates.

239. PG&E agreed to recalculate the diversity benefit adjustment to master-meter discounts to reflect the baseline quantities and rates that result from this case and related proceedings.

240. The joint study on line losses of submetered mobilehome parks, as contemplated in D.86-12-091, was not undertaken. The ALJ directed PG&E and WMA to develop a joint study on line losses, as had been previously ordered by the Commission.

241. Losses for PG&E's entire secondary distribution system, including transformation from the primary to secondary level, average 3.61%.

242. Estimates of line losses of submetered mobilehome parks can be based on the annual average secondary distribution level loss adjustment PG&E used in its marginal cost studies in this case.

243. PG&E's master-meter discount study shows that the marginal consumption of 9 of the 23 parks studied, or 39%, was

within Tier 1 and that roughly 80% of total consumption was within Tier 1.

244. We determined in D.88-09-025 that RV parks could qualify for baseline allowances if they rent at least 50% of their spaces on a month-to-month basis for at least nine months of the year. RV parks that meet these criteria are also eligible for service on Schedule EM.

245. Current marginal customer costs for the small light and power class are well above the levels of the current customer charges or the charges recommended in this case.

246. DRA demonstrated in PG&E's last general rate case that the costs of replacing direct current meters for customers on Schedule A-15 would be equalized over time at $7.80 per month.

247. The recommended customer charges for the medium light and power class are well below estimates of marginal costs.

248. PG&E proposes to establish a two-tier energy charge for Schedule A-10 instead of the current flat rate.

249. The customer may interpret PG&E's proposals for Schedule A-10 as a signal either to reduce demand or to increase overall consumption.

250. In D.86-12-091 in PG&E's last general rate case, we required PG&E to offer conjunctive billing to schools.

251. The first workbooks on conjunctive billing were not mailed to schools until February 1988.

252. PG&E proposes to divide Schedule E-20 into two schedules. The new Schedule E-19 would serve customers with maximum demands of between 500 and 1000 kW. Schedule E-20 would continue to apply to customers with more than 1000 kW of maximum demand.

253. DRA's recommendations for customer charges at the primary and secondary distribution level of Schedules E-19 and E-20 make reasonable progress toward marginal cost without undue effect on customers' overall rates.

254. DRA's approach to maximum demand charges has the virtue of treating all voltage levels consistently, and it makes substantial progress toward EPMC.

255. The recommendations of DRA for calculating the on-peak demand charge move significantly toward EPMC without causing undue increases for any voltage level.

256. In D.86-12-091, we adopted an average rate limiter for summer rates for customers connected at the primary and secondary levels. In this case, PG&E and DRA propose to develop separate limiters for Schedules E-19 and E-20 and to increase the average rate limiter to 25% above the average summer rates at the secondary level of those schedules.

257. The on-peak rate limiter was adopted in D.86-12-091 to mitigate the bill effects of changes in revenue allocation and rate design on extremely low load factor customers, including standby customers that have low on-peak energy usage. PG&E agrees to use DRA's model to set on-peak rate limiters.

258. Nonfirm service allows PG&E to be able to reduce demand from certain customers at key times, particularly when high system demand, transmission and distribution system overloads, or equipment failure jeopardizes PG&E's ability to meet its customers' need for electricity.

259. PG&E, DRA, and CLECA agreed on a proposal for resolving the treatment of nonfirm services in this case. The proposal was presented as a joint exhibit (Exhibit 88) in the update phase of the hearings.

260. If the costs of nonfirm options exceed the marginal costs of coincident demand-related capacity, it would be cheaper for the utility to go ahead and obtain the extra capacity at the marginal cost than to pay the more costly incentives to nonfirm customers for the same amount of capacity.

261. Only 0.06% of coincident demand-related capacity costs are imposed by nonfirm customers.

262. Because of the ability of the current curtailable options to avoid coincident demand-related costs, greater value, and a greater incentive, should be assigned to this element than to interruptibility or economic dispatch.

263. Nonfirm customers connecting at the distribution level avoid additional costs associated with coincident demand, a portion of the marginal primary distribution capacity costs.

264. The value of interruptible service is related to system-wide disturbances, and the same incentive should apply regardless of voltage level.

265. All extended contracts for nonfirm service will expire before the end of this year.

266. Simultaneous telephone and printed notification of curtailments has improved the effectiveness, speed, and accuracy of PG&E's notifications.

267. No customers have signed up for service under Schedule E-24, and only one customer receives service under Schedule E-25.

268. ACWA proposes an experimental Schedule E-11 that would have an on-peak period of three hours, rather than six, and an increased on-peak energy rate.

269. In D.86-12-091, we adopted a billing adjustment factor of 85% for standby customers.

270. The present average rate limiter applies to all customers on Schedules E-19 and E-20 except those taking standby service.

271. The lack of an average rate limiter has a particularly detrimental effect on small cogenerators.

272. Customers who operate their own generators in parallel with PG&E's system are required by Rule 21 to be responsible for the costs of interconnection facilities. The customers may either install, own, and maintain the facilities directly, or they may pay PG&E to supply these services.

273. Customers' interconnection facilities may also be adequate to supply the customers with standby power.

274. DRA recommends that in future general rate cases, PG&E should differentiate between backup, maintenance, and supplemental service for all standby customers. The only way to distinguish between the types of standby service is by metering generator output.

275. Schedule S currently provides for up to 300 kW of free contract capacity for customers with generators powered by sources other than fossil fuels. PG&E and DRA recommend termination of this experimental allowance, because customers should be charged on the basis of costs, whatever the technology of their generators may be.

276. PG&E proposes two experimental schedules, Schedules ED-19 and ED-20, for customers in special enterprise zones established by the State of California.

277. The agricultural class is farther away from EPMC, as calculated from current marginal costs, than any other customer class.

278. Both DRA and PG&E recommend a $10 monthly customer charge for agricultural accounts.

279. Both PG&E and DRA agree that the increase to maximum demand charges to Schedules AG-1, AG-R, AG-V, and AG-4 should be capped consistently with the overall percentage cap used in intraclass rate design. DRA caps the increases to these schedules at five percent over the total cap on intraclass and interclass agricultural revenue allocation.

280. For Schedules AG-5B and AG-5C, the maximum demand charges currently exceed an EPMC-based allocation of noncoincident capacity costs plus customer costs.

281. On-peak demand charges for agricultural TOU schedules can be set at EPMC levels without undue effects on bills.

282. The demand charge limiter was extended to the agricultural class in D.87-04-028.

283. Demand meters are not installed for agricultural accounts on the "A" series. One of the components of the calculation of the demand charge limiter, the seasonal billing demand, cannot be determined without a demand meter.

284. DRA recommends increasing the demand charge limiter by 5% over the cap used in the intraclass revenue allocation within the agricultural class.

285. Assigning Schedules AG-5B and AG-5C their full EPMC shares of the agricultural class' revenue allocation results in a rate that is above marginal cost but competitive with diesel- or liquid petroleum-fueled pumping.

286. The minimum bill creates adverse and unintended consequences for customers on the AG-5 schedules.

287. Schedule AG-6 was established as an interim schedule to accommodate customers who were waiting for the installation of TOU meters needed for service on Schedule AG-5.

288. For customers requesting service on Schedules AG-4, AG-V, or AG-R, the backlog was 783 TOU meters as of the end of May 1989. The current average delay between a customer's request for a TOU schedule and installation of a TOU meter is 30 days.

289. The parties differed on how to develop streetlighting facilities charges. PG&E relied on the method adopted in its last general rate case decision, the original cost less depreciation-replacement cost new (OCLD-RCN) method. Cal-SLA and DRA support an approach designated as the replacement cost new-economic carrying charge (RCN-ECC) method.

290. PG&E's recommended A&G factor was developed specifically for the streetlighting class for use in calculating maintenance charges.

291. Because of a miscalculation in PG&E's last general rate case, the facilities charges PG&E proposes in this case are considerably higher for some customers than present charges.

292. PG&E's cost of painting streetlighting poles averages $0.82 per pole per month.

293. High pressure sodium vapor facilities served under Schedule LS-1, Class B would be charged identical rates if they were served under Class A.

294. DRA proposes "Funding, Evaluation, and Implementation Principles" (FEIP) for DSM. The FEIP consist of some 65 individual tenets covering all aspects of PG&E's current DSM program.

295. We have stated a series of principles for evaluating DSM programs in the various decisions we have made on DSM issues over many years. Many of the tenets of the FEIP are restatements of policy determinations we have already made.

296. The current relation of marginal costs to average retail rates leads to low benefit-cost ratios for the RIM.

297. PG&E proposes to consolidate the existing Direct Weatherization, Low-Cost Weatherization, and Community Weatherization programs under the TCDAP to reduce administrative costs and improve the Direct Assistance programs' cost-effectiveness.

298. Because of the high cost of retrofitting, the cheapest time to extend gas lines into new developments is when they are under construction.

299. Under the TRC test, incentive programs have very high benefit-cost ratios.

300. Spending on the Energy Efficiency Incentive program dropped considerably in 1989 compared to 1988.

301. The Area Development Program is part of a coordinated effort on the state and local levels to stimulate economic growth in certain depressed areas. These economic benefits, in combination with the relatively small amount devoted to this program, outweigh concerns about long-term costs.

individual service contracts that has occurred in recent years will continue in 1990 and beyond.

302. There is no reason to believe that the rapid increase in individual service contracts that has occurred in recent years will continue in 1990 and beyond.

303. Shade trees reduce the need for summer cooling in two ways. When they are planted next to buildings, they shelter the structure from the sun's rays. In addition, shade trees help dissipate "heat islands," which raise the temperature of urban areas several degrees during summer days and thus increase the demand for cooling.

304. Compact fluorescent lighting is at a technical and economic level where it could make a substantial contribution to reducing the electricity consumption of lighting.

<u>Conclusions of Law</u>

1. The Commission Advisory and Compliance Division shall investigate the extent to which conservation has led to reduced baseline quantities. The report of this investigation will be due on April 1, 1990.

2. PG&E should do everything permitted by existing labor contracts to assign bilingual workers to offices that serve areas with a substantial population of customers who speak only a foreign language. In addition, when labor contracts come up for negotiation, PG&E should seek to obtain some flexibility in assigning bilingual workers to offices where their linguistic skills are needed. PG&E shall continue to work with the Public Advisor's Office to develop notices that are meaningful to those who do not speak English.

3. The increases in rates and charges authorized by this decision are just and reasonable and should be adopted.

4. The agreed-upon labor escalation rate of 2.75% in 1988 and 1989, and the agreed-upon non-labor escalation rates of 5.17% for 1988 and 4.6% for 1989 are reasonable and should be adopted.

5. PG&E should be authorized to recover PG&E's estimated costs for a share in the HVDC expansion project, subject to refund.

6. PG&E's progress in rewriting the CIS should be reviewed in the next general rate case.

7. The guidelines for plant held for future use, as set forth in Appendix L, are reasonable and should be adopted.

8. All costs of owning and operating Diablo Canyon should be segregated, without consideration of those costs which might have been incurred by PG&E regardless of the existence of the facility.

9. All costs of owning and operating Diablo Canyon should be segregated, including costs incurred at the highest managerial levels.

10. PG&E should be required to conduct a current, full-scale use study of expenses booked to Administrative and General Accounts, and to carefully and completely allocate such expenses between Diablo Canyon and other operations. PG&E should be required to carefully develop a written format, to review the format with DRA and other interested parties, and to obtain itemized, documented responses from all departments, officers, and managers who record expenses in A&G accounts.

11. All costs incurred by PG&E in preparation of the use study, as well as for participation in the workshops, and further proceedings on this issue, shall be charged to Diablo Canyon.

12. Pending a complete, current use study of Diablo Canyon-related A&G expenses, the interim allocation of expenses as set forth in this decision, should be adopted.

13. The costs of initiatives to meet two of the three "main corporate priorities", Diablo Canyon and unregulated business investments, are not an appropriate cost of service.

14. D.88-12-083 requires all costs incurred as a result of operating Diablo Canyon to be segregated; not just the direct salary of Diablo Canyon employees, but also the salary, expenses and incentive bonuses paid to other PG&E employees (such as those in Corporate Communications) who devote time or effort to this corporate priority.

15. PG&E should be required to conduct a facility-by-facility use study of common plant in order to determine the amount of common plant which is properly allocated to Diablo Canyon.

16. PG&E should be required to maintain strict segregation of all costs incurred in pursuing unregulated business activities, both the direct salaries of Enterprise employees and the salaries and expenses of other employees who contribute to this effort.

17. The utility bears the burden of proof of reasonableness, not only with respect to the planning and conduct of a given abandoned project, but also regarding the cancellation, which must have occurred promptly when conditions warranted. The utility must demonstrate that the project which it ultimately abandoned was reasonable throughout the project's duration in light both of the relevant uncertainties that then existed and of the alternatives for meeting the service needs of its customers.

18. PG&E, in its present application has not met its burden of showing that these abandoned projects satisfy the criteria established in D.83-12-068.

19. There is no need for an annual review of the costs and benefits of the SMUD contract prior to the next general rate case. Revenues from discounted sales will be included in authorized base revenues, subject to ERAM. The value of discounted sales revenues will be $49,636,000.

20. DRA's labor adjustment to normalize 1987 labor expenses is reasonable and should be adopted.

21. The adjustment recommended by DRA to PG&E compensation is based on an inadequate salary survey and should not be adopted.

22. PG&E should be required effective January 1, 1990, to itself directly translate account information before submitting accouunting information to the Commission. Such translation should be done promplty, and should be excused only with the express consent of the Commission staff.

23. PG&E should be required to follow specific procedures, as set forth in this decision, to ensure that the accounting system which is developed fully meets both the needs of PG&E management and our needs of effective and timely regulatory oversight.

24. PG&E should be required to complete its investigation of the manufactured gas plant sites it now owns, approximately 31, prior to filing its next general rate application. PG&E should be excused from undertaking or completing an investigation at a particular site only if it can document that the delay is caused by factors outside of its control, or if the responsible oversight agency concurs in the decision not to further investigate a particular site.

25. PG&E should be required to file an annual report on the meter location program with the Commission's Safety Division, in the same format and filed at the same time as the annual report on the pipeline replacement program which PG&E submits pursuant to D.86-12-095. The first annual report on the meter replacement program should be filed May 1, 1991.

26. A special burden is borne by the applicant in a rate case to demonstrate conclusively not only that affiliated intercompany transactions are reasonable in that they do not create a burden on the consumer, but that the affiliated relationships afford the maximum gains in efficiency or productivity and the greatest savings in costs to the consumer.

27. The Commission should direct an independent audit of PG&E and PG&E Enterprises to determine, among other matters, (1) the transfer of goods and services between PG&E and Enterprises, (2) billing, financial and recordkeeping practices, (3) cost allocation, and (4) personnel practices.

28. It is reasonable to adopt an RD&D budget for the test year of $36,732,000, broken down into $29,690,000 for electricity and $7,042,000 for gas.

29. For purposes of this proceeding, the long-term resource plan should reflect the load forecast developed by PG&E, reduced by the effects of the DSM program we authorize.

30. The long-term plan developed for this case should include a consideration of the spot market for capacity from the Northwest, which has proved to be a reliable and cheap resource in recent years. The resource plan should include 500 MW of spot capacity.

31. The resource plan should reflect the CEC's findings on the amount of firm capacity PG&E will be able to purchase from the Northwest under existing contracts.

32. The resource plan used in this proceeding should include pending resources as firm capacity.

33. For the purposes of this proceeding, the CEC's assumption that the municipal utilities will have 848 MW of COTP's capacity available to them is reasonable.

34. DRA's approach to pricing Northwest power is reasonable and consistent with our treatment of this issue in recent years, and is supported by the behavior of sellers over the past few years.

35. PG&E's approach to modeling the Northwest Intertie is reasonable for this proceeding.

36. The sales from Pacific Power and Light to SMUD should be included in the estimates of the Northwest's surplus energy.

37. The approach taken by the CEC in ER-7, which split the difference between DRA's (and CEC's staff) and PG&E's estimates of capacity from QFs and self-generation, is reasonable.

38. Generic resources should not be included in the resource plan for purposes of general rate case.

39. The full capacity of Helms should be included in the resource plan for this proceeding.

40. The capacity upgrades associated with relicensing of PG&E's hydroelectric facilities should be included in the resource plan.

41. The status of Rancho Seco should be reflected by reducing the resources available to PG&E by 600 MW.

42. The savings from DSM included in the resource plan should be those associated with the DSM funding adopted in this general rate case.

43. The demand forecast used in this proceeding should reflect net first-year savings of 51.7 MW of peak capacity and 408 GWh of energy.

44. DRA's approach to pricing as-available QFs is reasonable.

45. DRA's projections of fuel prices are reasonable.

46. DRA's recommended modeling procedures are reasonable as guidelines for the way issues relating to production cost models should be addressed, but the administrative law judge should have the discretion to establish deadlines for these steps and to alter this procedure to fit the circumstances of a particular case.

47. DRA's approach to modeling the capacity of the Diablo Canyon nuclear power plant is reasonable.

48. DRA's monthly load shapes are reasonable for modeling purposes.

49. Spinning reserve requirements should reflect all of Helms' capacity.

50. Production costs present a more accurate picture of the system's operation, and DRA's position on modeling dispatch costs is reasonable.

51. PG&E has sufficient resources to meet expected demands for the near future, and no PG&E-owned additions are proposed for the test year cycle.

52. The assessment of the need for new resources should be performed in the Biennial Resource Plan Update proceeding, and the resource plan used in the general rate case is not precedent for or binding on the resource plans developed in the BRPU.

53. The capacity assumed for oil- and gas-fired generating units should be adjusted to reflect age-deratings that contributed to the CEC's decision to lower the target reserve margin to 17.5%.

54. The calculation of the ERI for use in this case should reflect determinations of this decision.

55. DRA's adjustments for franchise fees and uncollectibles are reasonable.

56. General plant loading factors of 9.21% for marginal distribution capacity and customer costs, 3.69% for marginal transmission capacity costs, and 2.10% for marginal generation capacity costs, are reasonable.

57. After adjustments for FF&U, a reasonable estimate of marginal generation capacity cost is $56.17/kW-yr.

58. It is reasonable to adjust the full annualized cost of a combustion turbine of $56.17/kW-yr. by the six-year average ERI to develop the marginal generation capacity cost used for revenue allocation and rate design.

59. After adjustments for FF&U, a reasonable estimate of marginal transmission capacity costs is $31.80/kW-yr.

60. After adjustments for FF&U, a reasonable estimate of marginal primary distribution capacity cost is $53.00/kW-yr.

61. After adjustments for FF&U, a reasonable estimate of marginal secondary distribution capacity costs is $6.87/kW-yr. This figure should be examined in the next general rate case. As background to that examination, PG&E should perform a study on the expected need to upgrade modern distribution facilities because of load growth.

62. PG&E and DRA's general approach to marginal customer costs is reasonable.

63. A small part of secondary distribution O&M costs should be allocated to capacity. The remainder and the bulk of these O&M costs should be allocated to marginal secondary distribution customer costs.

64. Use of the standing stock approach to develop the characteristics of customer costs is consistent with marginal cost principles.

65. PG&E's revised marginal customer costs for medium light and power class and the primary and secondary voltage levels of the large light and power class, adjusted for DRA's recommended vacancy factor and FF&U, are reasonable.

66. The costs of customer line extensions should be excluded from the calculation of transmission level marginal customer costs. As a reasonable estimate of transmission level marginal customer costs is $49,777.25 per customer-year, adjusted for FF&U.

67. DRA's approach will most accurately reflect the marginal customer costs of the streetlighting class.

68. The customer accounting costs of the streetlight facility cost study should be used to develop marginal customer costs for the streetlighting class.

69. Both PROMOD and ELFIN are acceptable for purposes of calculating marginal energy costs using the Zero Intercept Method.

70. For the purposes of this rate case, we will define the gas portion of marginal energy costs to be all components of the UEG rate except customer costs. The method we adopt here should also be considered interim and subject to revision when we develop better approaches to defining marginal costs for natural gas.

71. Focusing on only one element of marginal cost while ignoring others leads to distortion in the cost relationships among all the marginal cost components.

72. The marginal costs set forth in Appendix H are reasonable.

73. TURN's proposed NOx adder to marginal energy costs should not be adopted.

74. PG&E's proposal to split the existing large light and power class into the E-19 and E-20 classes is reasonable.

75. Class coincident demands for 1990 should be estimated using historical load factors derived from 1985, 1986, and 1987 load data, weighted by PG&E's hourly generation loss of load probability (LOLP) forecasted for 1990. Each class' hourly loads for each of the historical years should be scaled so that multiplying each year's hourly percentage times PG&E's expected system loads for the test year produces the test year's sales forecast.

76. Marginal generation capacity costs should be allocated entirely on the basis of coincident demand.

77. The diversity of customers' maximum demands should be reflected in the noncoincident demand as measured at the final line transformer.

78. DRA's allocation of marginal transmission and distribution capacity costs is reasonable.

79. DRA's proposal to increase marginal generation capacity costs by the percentage of the target reserve margin should not be adopted.

80. In this case, application of a cap of 5% plus SAPC requires caps for only the agricultural and small light and power classes, and the 5% limit keeps these increases within a range that we find reasonable in light of all the circumstances.

81. It is reasonable in this case to move one-third of the way toward the EPMC allocation for the streetlighting class. This reduction should continue during the next three years, so that the streetlighting class will receive its EPMC allocation by the next general rate case.

81a. It is reasonable to cap the interclass allocation for the agricultural class at 2% above SAPC.

82. The revenue shortfall due to the application of caps and the movement of the streetlighting class toward EPMC should be recovered from all uncapped classes on an EPMC basis.

83. A revenue allocation based on the principles we adopt in this case should take place whenever there is a substantial change in revenue requirement during the rate case cycle. The marginal

capacity and customer costs we adopt in this decision should be used in performing this allocation. In these subsequent allocations, we will use caps and floors of SAPC plus or minus 5% as a guideline in developing a revenue allocation, except for the streetlighting class.

84. The ideal allocation of revenues from special contracts would maintain the relationships among the customer classes that would exist if the need for special contracts had never arisen.

85. Removing all sales and revenues from special contracts from the allocation process results in a reasonable treatment of revenues from special contracts.

86. Capacity savings from nonfirm service and load management programs should be credited against these customers' rates. The revenue allocation should then spread the costs of the associated discounts to all customers.

87. Revenues from Schedule AG-5 should be included in the revenue allocation like revenues from any other tariff schedule.

88. A separate ERAM account for the agricultural class is not reasonable.

89. AWCA has failed to show that any substantial benefits are likely to result from investigating whether all water pumpers should be classified as agricultural customers.

90. ACWA has failed to develop a record to support a reliability adjustment for rural customers.

91. The revenue allocation to schedules within a particular class should be bounded by a cap or floor of 5% above or below the class' average percentage change that results from the interclass allocation.

91a. The revenue responsibility for Schedule AG-5 should be set equal to schedule's marginal cost revenue responsibility. The remaining revenue allocation to the agricultural class should be allocated to the other agricultural schedules on an SAPC basis.

92. DRA's approach should be followed in developing the usage characteristics, number of customers, and resulting revenue allocation to the new residential TOU schedules.

93. The residential customer charge recommended by DRA is not reasonable at this time.

94. Substantial progress should be made at this time toward reducing the differential between Tier 1 and Tier 2 rates. The differential between Tier 1 and Tier 2 rates, expressed in cents/kWh, should be reduced 25% in connection with this case.

95. The calculation of Tier 1 rates should include minimum bill revenues.

96. Changes in the tier differentials should take place on May 1, 1990, when baseline quantities are adjusted.

97. PG&E and DRA's principles for calculating baseline quantities and DRA's proposed target baseline quantities are reasonable.

98. PG&E should continue the current practice of adjusting baseline quantities every May and phasing in toward the target quantities. Rate levels should be adjusted at the same time to make the change in quantities revenue-neutral.

99. It is reasonable to apply the 15% LIRA reduction to the minimum bill.

100. Sales under Schedule OL-1 should be subject to the LIRA surcharge.

101. The LIRA surcharge should be calculated by the method illustrated in DRA's supplemental brief. The surcharge should be based on the rates that will become effective on January 1, 1990, and should also recover the discounts paid in November and December 1989 and other appropriate costs of this program.

102. It is appropriate to emphasize the dissemination of accurate cost information through rates.

103. Retaining a baseline credit for Schedule E-7 will make this rate option more attractive to low-usage customers.

104. A capped EPMC approach to revenue allocation of Schedule E-7 should continue to be used.

105. The Schedule E-7 baseline credit should be derived from the difference between Schedule E-1's Tier 1 and Tier 2 rates,

minus Schedule E-7's meter charges prorated over average baseline usage.

106. The baseline credit should be limited so that Schedule E-7's off-peak rate goes no lower than marginal cost.

107. DRA's proposal to move all seasonal and TOU differentials halfway to EPMC-based levels is reasonable.

108. Schedule E-8 is a reasonable and administratively simple effort to compete for customers who heat with wood or propane. Rate design for this schedule should assume the average consumption estimated by DRA and include a customer charge and seasonal energy rates set at full EPMC levels.

109. The tariff for Schedule E-8 should have a special condition requiring customers who choose this option to remain on this schedule for at least one full year.

110. The proposed Schedule E-9 should not be adopted.

111. Master-meter discounts based on PG&E's cost studies and on DRA's analyses should be adopted, except for the discount for Schedule GT.

112. The discount for Schedule GT should not be changed at this time.

113. It is reasonable to adopt a minimum average rate for master-meter customers equal to the average ECAC rate for Schedule ET and the core WACOG for Schedule GT.

114. PG&E should reexamine the basis for its cost studies and to put extra effort into developing an accurate and easy-to-verify method for calculating the master-meter discounts. The results of its efforts should be reported as part of its next general rate case application.

115. PU Code § 739.5 requires the net master-meter discount to be based on "the reasonable average costs to master-meter customers of providing submeter service."

116. The underlying plant cost and other components of the master meter discount should reflect an average vacancy rate.

117. PG&E should recalculate the diversity benefit adjustment to master-meter discounts to reflect our adopted rates and baseline quantities.

118. We cannot base the line loss adjustment to master meter discounts on studies of the quality of Exhibit 94.

119. A line loss percentage associated with submetered mobilehome parks of 2.098% should be adopted.

120. It is reasonable to adopt DRA's approach of basing the adjustment for line losses to submetered mobilehome parks on a weighted average of Tier 1 and Tier 2 rates. The weighting should be based on the data from Exhibit 17, p. 3-10.

121. PG&E should develop studies of line losses of submetered mobilehome parks. The results of this study shall be presented as part of PG&E's next general rate case.

122. Master-meter discounts of $10.50 per space per month for Schedule ET, $2.85 per space per month for Schedule ES, $6.32 per space per month for Schedule GT, and $3.60 per space per month for Schedule GS are reasonable.

123. The policy we developed in D.88-09-025 on baseline allowances for RV parks does not need to be modified at this time.

124. If an RV park rents at least 50% of its spaces on a month-to-month basis to one or more tenants for at least nine months of the year, then the tenants of such spaces should be considered permanent residents who are also eligible for baseline allowances.

125. PG&E should work with CTPA to develop a survey of RV parks to determine: (1) the proportion of parks that meet our criteria for qualifying for baseline allowances, as set forth in D.88-09-025; (2) the proportion of parks that have installed submeters for at least some of their spaces; and (3) the proportion of RV park spaces that are rented on a month-to-month basis. PG&E should submit this information, ideally in the form of a joint

report, with exceptions or dissents, if necessary, on or before January 1, 1991.

126. Customer charges for commercial and industrial customers should collect a greater share of marginal customer costs.

127. A customer charge of $7.50 is reasonable for the small light and power class.

128. A reasonable facilities charge for customers on Schedule A-15 is $7.80 per meter per month.

129. A customer charge of $63.00 per month is reasonable for Schedules A-10 and A-11.

130. PG&E's proposed two-tiered energy charge for Schedule A-10 should not be adopted.

131. PG&E should continue its conjunctive billing experiment until at least December 31, 1990, and work with SCRUB during this time to attempt to get responses to the experimental offerings from more schools. If PG&E concludes that this experiment is not cost-effective at the end of 1990, it may apply again to end the program as part of the next rate design window occurring after 1990.

132. Edison's request to suspend its conjunctive billing offering should not be granted in this proceeding.

133. The new Schedule E-19 should be authorized.

134. PG&E should incorporate appropriate restrictions in its tariffs to prevent artificial movement from Schedule E-19 to Schedule E-20. A reasonable initial restriction is to require customers served under Schedule E-20 to take service on another schedule if maximum demand falls below 1,000 kW for eight months out of twelve.

135. DRA's recommendations for customer charges for Schedules E-19 and E-20, including its recommended additional increments of $190 and $200 for curtailable and interruptible service, are reasonable.

136. DRA's approach to determining maximum demand charges for Schedules E-19 and E-20 is reasonable.

137. On-peak demand charges should be modified by the ERI to take into account the relation between the utility's actual reserve margin and its target reserve margin.

138. The average rate limiter should apply separately to Schedules E-19 and E-20 and should be set at 25% above the average summer rate for the secondary voltage level of each schedule. The level of the limiter should increase over time and should never decrease, even if the average summer rate for the secondary voltage level decreases.

139. It is reasonable to continue the on-peak rate limiter and to use DRA's model to calculate its proper level.

140. The general array of nonfirm options contained in Exhibit 88 is reasonable.

141. Exhibit 88 develops incentives for curtailable service that exceed the costs that service allows the system to avoid.

142. The perfectly interruptible customer would impose no coincident demand-related costs on the system, and the appropriate incentive for perfect interruptibility would equal all marginal costs associated with coincident demand. These costs constitute the maximum reasonable incentive for nonfirm customers.

143. The proposed and existing nonfirm options are less valuable to the system than the hypothetical perfectly interruptible customer.

144. The total marginal capacity costs associated with coincident demand provide a reasonable estimate of the maximum value the proposed nonfirm options offer to PG&E's system.

145. Interruptible credits should be related to the costs the utility avoids by having customers available for interruption.

146. It is reasonable to adopt $16.28/kW-yr. as the incentive for customers with UFRs.

147. The annual interruptible incentive should be converted to a cents/kWh basis and paid as a credit against the interruptible customer's monthly energy use.

148. The question of the proper level of nonfirm service incentives should be considered again. PG&E should submit a study and a proposal on nonfirm rates in connection with the workshops and hearings we will direct the ALJ to arrange.

149. After subtracting the interruptible credit from the maximum incentive for nonfirm customers, it is reasonable to assign 75% of the remaining amount available for nonfirm incentives to curtailable service and 25% to the experimental economic dispatch option.

150. At the transmission level, incentives of $50.79/kW-yr. for curtailable service and $16.93/kW-yr. imputed to the economic dispatch option are reasonable.

151. Incentives of $64.87/kW-yr. for curtailable service and $21.62/kW-yr. for the economic dispatch option are reasonable for nonfirm customers connecting at either the primary or secondary distribution level.

152. Coincident demands for nonfirm schedules should not be adjusted in the revenue allocation to reflect the expected demands of nonfirm customers during curtailments.

153. The penalty for each failure to curtail when requested should be 80% of the incentives we have adopted.

154. The curtailable credit should be spread in a way that maintains the relative price signals expressed through demand charges and energy rates.

155. PG&E should be authorized to offer the economic dispatch option described in Exhibit 88, subject to the modifications suggested in this decision.

156. If an interruptible customer also elects to be dispatchable on economic grounds, the 30-curtailment limitation should not apply to automatic interruptions for underfrequency events.

157. For this rate case cycle, PG&E should report annually on the results of implementing and operating the economic dispatch

option and submit the option to annual review. This report and review should take place in connection with the reasonableness phase of the ECAC proceeding.

158. Extended contracts for nonfirm service should not be extended any further. Customers with extended contracts had no reasonable basis for expecting those incentives to continue beyond the terms of the contracts, and other ratepayers would be harmed by continuing the old incentives.

159. The effects of changes in nonfirm incentives should be phased in, as proposed by PG&E.

160. Nonfirm customers should be required to make available a telephone line and space for a notification printer.

161. Anchor did not show that changing the setting of the UFRs is desirable or justified.

162. The function of the nonfirm service program in PG&E's system needs to be clearly defined. There should be a logical, economic basis for nonfirm incentives. The ALJ should arrange for additional informal meetings or formal hearings, as necessary, to achieve the goal of refining nonfirm incentives.

163. Schedule E-24 should be eliminated.

164. DRA's proposal for a new option based on Schedule E-25 is reasonable.

165. It is reasonable to authorize an experimental Schedule E-11, based on ACWA's proposal as modified by PG&E.

166. Customer charges for Schedule A-RTP should be the corresponding charges of Schedules E-19 and E-20, differentiated by both voltage level and the size of the customer's load.

167. Maximum demand charges for Schedule A-RTP should be differentiated by voltage level.

168. PG&E should work with DRA in reviewing the initial results of the experimental Schedule A-RTP, before expanding the program in 1991.

169. The capacity charge for standby service should be set at the level of the maximum demand charges for Schedules E-19 and E-20.

170. The 85% billing adjustment factor for standby customers should continue for this rate case cycle.

171. The average rate limiter should apply to all of a standby customer's regular service load, in the same way that it applies to other customers on Schedules E-19 and E-20. The maximum demand used to determine the regular service charge for any month should be reduced by the customer's standby demand in that month. The standby contract capacity charge should not be subject to the average rate limiter.

172. Customers should not be charged twice for the same services or facilities. Customers who are responsible for most, but not all, of their special facilities costs should have the option of assuming full responsibility for those facilities.

173. As part of its next general rate case, PG&E should submit a study of the costs of metering and obtaining the data needed to distinguish between the different types of standby service.

174. The unconventional technology allowance of Schedule S should be eliminated.

175. The experimental Schedule ED proposed by PG&E should be authorized, subject to the following limitations. First, the experimental schedule should be limited to eight customers, rather than the twelve PG&E proposes. Second, the discounts should not be available for load that merely relocates from the service territory of another California utility. PG&E should take advantage of the opportunity presented by this experiment to ensure that these new customers are informed of cost-effective conservation and load management measures they may take

to reduce their electric bills and the load they place on the system.

175a. The record in this proceeding should remain open to take testimony on the specific issue of whether the adopted rates for customers served under Schedule AG-5 are competitive with alternative pumping fuels. This matter should be decided before May 1, 1990.

175b. PG&E and CACD should conduct a joint study of the agricultural class' marginal costs and intraclass allocation and their implications for rate design. This study should be completed by November 5, 1990, and served on the Commissioners, DRA, CFBF, PUPC, the assigned ALJs, and any other party requesting a copy.

176. A $10 monthly customer charge for agricultural accounts is reasonable.

177. It is reasonable to adopt a cap for the maximum demand charges of Schedules AG-1, AG-R, AG-V, and AG-4, set at the level of 5% above the sum of the interclass and intraclass percentage caps.

178. DRA's recommendations for determining maximum demand charges for Schedules AG-5A, AG-5B, and AG-5C, subject to a floor of current charges, are reasonable.

179. On-peak demand charges for agricultural TOU schedules should be set at EPMC levels.

180. The demand charge limiter is designed to allow minimal energy use during a particular season. If the customer is recording more than the allowed minimal use, then that customer is not truly a seasonal customer of the sort that the demand charge limiter is designed to protect.

181. CFBF's proposal to apply demand charge limiters to the "A" series of agricultural tariffs should not be adopted.

182. For the next rate case cycle, the demand charge limiter should be retained for the agricultural class with the increases advocated by DRA.

183. TOU energy charges for the agricultural class should be set so that the average rate in each TOU period is proportional to the combined marginal cost of energy and coincident capacity for each TOU period.

184. The incremental cost of agricultural TOU metering above standard meter costs should be added to allocated revenues for TOU schedules to produce the total revenue requirement. The meter charges on agricultural TOU schedules should be set at the incremental cost of TOU metering, rounded to the nearest five cents.

185. Agricultural energy and on-peak demand charges should be set residually to collect revenues equal to the total revenue requirement minus the revenue from customer charges, maximum demand charges, and meter charges. The on-peak energy charges on TOU schedules should be set residually from the revenue allocated to the on-peak period.

186. Giving Schedules AG-5B and AG-5C their full EPMC shares of the agricultural class' revenue allocation is reasonable.

187. It is reasonable to eliminate the minimum bill for Schedules AG-5A, AG-5B, and AG-5C.

188. It is reasonable to allow PG&E to continue service under Schedule AG-6 for up to two billing cycles after a customer requests service under Schedule AG-5. PG&E should install the necessary TOU meters by May 1, 1990 for all customers on Schedule AG-6 as of January 1, 1990.

189. The interim rate proposed by CFBF is not justified at this time.

190. PG&E should submit a report stating the number of agricultural TOU meters installed in 1989, the number of requests for conversion received in 1989, by month and by schedule, the backlog by schedule existing at the end of 1989, and the average delay in responding to a request for conversion. The report will be due on March 15, 1990, and should be served on CFBF, PUPC, ACWA, DRA, and any other party making a specific request to PG&E.

191. PG&E should continue the agricultural interruptible program for this rate case cycle at a minimum of the current level of participation. The interruptible credit should be paid on the basis of performance, rather than participation. In addition, PG&E should consider DRA's recommendations on the interruptible service charge and make any appropriate proposals for this change in the next rate design window proceeding.

192. The RCN-ECC approach to setting streetlighting facilities charges leads to rates that approximate marginal costs without any

attempt to relate those costs to the appropriate revenue requirement.

193. The OCLD-RCN approach to calculating facilities charges for the streetlighting class is reasonable.

194. The A&G adjustment used by PG&E reflects more precisely the A&G associated with the maintenance of streetlighting facilities.

195. We will adopt PG&E's proposed phase-in of streetlighting facilities charges for this rate case cycle.

196. A fee of 82 cents per pole per month for pole painting for streetlighting customers is reasonable.

197. PG&E's proposal to transfer the high pressure sodium vapor facilities served under Schedule LS-1, Class B, to Class A, is reasonable.

198. The TOU fractions used in developing streetlighting rates should reflect the effect of daylight savings time.

199. The FEIP should not be adopted in their entirety at this time.

200. PG&E's general rate case is not an appropriate forum for adopting general principles on DSM that apply to all utilities.

201. Funds allocated to a specific DSM program area should largely stay within that area.

202. Energy efficiency incentive programs and load management programs are the appropriate portions of DSM that are intended to serve as alternatives to supply-side programs. We adopt tenets III.A, IV.A, and VIII.A of DRA's proposed FEIP, as stated in Appendix A of Exhibit 110.

203. Under present circumstances, it is reasonable to pay most attention to the Total Resource Cost test, and we adopt tenets III.B, III.F, III.G, IV.B, and IV.F of DRA's proposed FEIP, as stated in Appendix A of Exhibit 110.

204. The primary purpose of the Natural Gas Home program is to overcome market barriers to installing efficient natural gas appliances.

205. PG&E has not adequately justified the need for the fuel substitution portion of its electric heat pump incentive program.

206. PG&E has failed to justify its Efficient Outdoor Security Lighting program.

207. A reasonable budget for the Area Development program is $1,000,000 for the electric program and $500,000 for the gas program.

208. PG&E's and DRA's installation goal of 20,000 TOU meters per year is reasonable. PG&E should continue to report on the progress of the voluntary TOU program as part of its annual ECAC cases.

209. Installing 20,000 TOU meters annually should be viewed as a minimum, and PG&E's estimated market saturation dates should be a goal, rather than merely an estimate. By the time of PG&E's next rate case, PG&E should have a well-developed plan for completing the saturation of the various markets for TOU meters.

210. PG&E should vigorously promote the planting of shade trees in its service territory. A coupon program targeted to specific areas or groups of customers should be part of this program.

211. PG&E should seek to maximize the cost-effectiveness of its incentive programs.

212. The DSM budget set forth in Table 8 is reasonable.

213. The rate increases authorized by this decision should be reduced by the available unspent DSM and RD&D funds from PG&E's last general rate case cycle.

214. Pending resolution of PG&E's petition to modify D.89-12-015 in the ECAC proceeding, the $103,700,000 at issue should not be put into rates.

INTERIM ORDER

IT IS ORDERED that:

1. The Commission Advisory and Compliance Division (CACD) shall investigate the extent to which conservation has led to reduced baseline quantities. The report of this investigation will be due on April 1, 1990. Copies shall be served on the Commissioners, the assigned Administrative Law Judges (ALJs), the Division of Ratepayer Advocates (DRA), Pacific Gas and Electric Company (PG&E), and any other party requesting a copy.

2. PG&E shall continue to work with the Public Advisor's Office to develop notices that are meaningful to those who do not speak English.

3. PG&E is authorized and directed to file with this Commission on or after the effective date of this order, and at least three days prior to their effective date, revised tariff schedules for electric rates as set forth in Appendixes.

4. The revised tariff schedules shall become effective on or after January 1, 1990 and shall comply with General Order 96-A. The revised tariffs shall apply to service rendered on or after their effective date.

5. All transcript corrections received are incorporated in the record.

6. PG&E is authorized to file attrition adjustments for 1991 and 1992 based on the results of operation adopted in these Appendices.

7. PG&E shall adjust its Electric Revenue Adjustment Mechanism (ERAM) effective January 1, 1991 to reflect full implementation of the guidelines for plant held for future use contained in Appendix L. The guidelines shall apply to all plant held for future use regardless of the date of acquisition.

8. PG&E shall file and serve a report in this proceeding, by March 31, 1990, which fully describes the standards, procedures and instructions employed by PG&E for directly charging or attributing all Diablo Canyon costs, including administrative and general (A&G) costs and costs of using common plant. The report shall include all instructions, operating procedures or accounting guidelines which will govern reporting and recording of time and expenses incurred by employees who work outside the gates of Diablo Canyon, including employees at the managerial level. DRA and interested parties who wish to comment on this report may do so by July 1, 1990.

9. PG&E is directed to conduct a current, full-scale use study of (1) expenses booked to Administrative and General Accounts, and (2) common plant. PG&E shall carefully and completely allocate all A&G expenses between Diablo Canyon and other operations. The design and format of the use study shall be developed by PG&E and reviewed by DRA and other interested parties in a workshop, to be moderated by CACD, in September, 1990. The use study shall be conducted, completed and filed with the Commission by December 31, 1990. PG&E shall obtain and retain itemized, documented responses from all departments, officers and managers who record expenses in A&G accounts. DRA and other parties may review and comment upon the study. Such comments shall be filed by March 15, 1991. Based on the submitted study and the comments of the parties, the Commission may, in its discretion, conduct further hearings to consider revisions to the revenue requirement for A&G or common plant expenses for the 1991 and 1992 attrition years.

10. PG&E shall conduct a facility-by-facility use study of common plant for the purpose of allocating common plant to Diablo Canyon. This study shall be conducted in conjunction with and under the same terms as the use study which PG&E will conduct for A&G expenses, under ordering paragraph 8, supra.

11. The costs of developing the direct charge system for A&G expenses and common plant, for conducting the use studies of A&G expenses and common plant, and filing the reports ordered above, shall be charged to Diablo Canyon.

12. In its next general rate application PG&E shall provide a full affirmative presentation on the level of overall compensation and a comparison to similar compensation levels in the relevant job markets.

13. PG&E shall file an annual report on the meter protection program with the Commission's Safety Division. This report shall be in the same format and filed at the same time as the annual report on the pipeline replacement program which PG&E submits pursuant to D.86-12-095. The first annual report on the meter replacement program shall be filed May 1, 1991.

14. PG&E shall complete its investigation of the manufactured gas plant sites it now owns, approximately 31, before it files its next general rate application. PG&E shall be excused from undertaking or completing an investigation at a particular site only if it can document that the delay is caused by factors outside of its control, or if the responsible oversight agency concurs in the decision not to further investigate a particular site. If PG&E has fully and prudently expended for site investigations the $6 million we previsiouly authorized and has not completed its investigation of all the sites it owns, PG&E is authorized to apply by advice letter for funds to investigate any remaining sites.

15. PG&E shall again present a multifactor productivity analysis in its next general rate case, and as part of the analysis, PG&E shall demonstrate how the forecasted multi factor productivity gains are reflected in its test year revenue requirement request.

16. Effective January 1, 1990, whenever PG&E submits monthly summaries of accounting information, PG&E shall directly translate all account information before submitting such information to the

Commission on tape. Such translation shall be done promptly, and shall be excused only with the express consent of the Commission staff.

17. PG&E shall file written reports with the Executive Director, beginning February 1, 1990, and at least each 90 days thereafter, on the development of the new accounting system. The reports shall describe work which is to be initiated in the coming quarter, and any changes in the system which will influence the Commission's ability to audit and review the accounts and records of the company. PG&E personnel responsible for the development of the new system shall meet and confer with DRA and CACD on these quarterly reports, if requested to do so by the Executive Director. The Executive Director may submit written questions, comments or suggestions to PG&E on the system, within 45 days of receipt of each report. If PG&E elects not to adopt the suggestions of the Executive Director, in whole or in part, it shall explain why it does not do so in the first quarterly report following receipt of the Executive Director's comments. All reports by PG&E and written comments by the Executive Director, shall be filed in this proceeding. The development of PG&E's new accounting system will be considered, as necessary, in this proceeding.

18. PG&E shall undergo an independent audit of the management, operations and interactions between PG&E and PG&E Enterprises. The specific areas of inquiry, the selection of the independent consultants and the procedures for review of the audit report, shall be in accordance with the terms of this decision.

19. The estimate of marginal secondary distribution capacity costs shall be examined in PG&E's next general rate case. As background to that examination, PG&E shall perform a study on the expected need to upgrade modern distribution facilities because of load growth.

20. PG&E is authorized to split the existing large light and power class into the E-19 and E-20 classes.

21. The Low-Income Ratepayer Assistance (LIRA) surcharge shall be calculated by the method illustrated in Appendix G. The surcharge shall be based on the rates that will become effective on January 1, 1990, and shall also recover the discounts paid in November and December 1989 and other appropriate costs of this program.

22. PG&E is authorized to offer Schedule E-8.

23. PG&E shall reexamine the basis for its cost studies for calculating master-meter discounts and shall report the results of its examination as part of its next general rate case.

24. PG&E shall develop studies of line losses of submetered mobilehome parks. The results of this study shall be presented as part of PG&E's next general rate case.

25. PG&E shall seek the cooperation of the California Travel Parks Association (CTPA) to develop a survey of recreational vehicle (RV) parks to determine: (1) the proportion of parks that meet our criteria for qualifying for baseline allowances, as set forth in D.88-09-025; (2) the proportion of parks that have installed submeters for at least some of their spaces; and (3) the proportion of RV park spaces that are rented on a month-to-month basis. PG&E shall submit this information as a report, with provision for CTPA's exceptions or dissents, if any, on or before January 1, 1991. The report shall be served on DRA, CACD, the assigned ALJs, and any other party requesting a copy.

26. PG&E shall continue its conjunctive billing experiment until at least December 31, 1990, and work with Schools Committee. to Reduce Utility Bills (SCRUB) during this time to attempt to get responses to the experimental offerings from more schools. If PG&E concludes that this experiment is not cost-effective at the end of 1990, it may apply again to end the program as part of the next rate design window proceeding occurring after 1990.

27. PG&E is authorized to offer Schedule E-19.

28. PG&E shall submit a study and a proposal on nonfirm rates. The ALJ shall arrange for informal meetings or formal hearings, as necessary, to achieve the goal of refining the nonfirm incentives.

29. PG&E is authorized to offer the economic dispatch option described in Exhibit 88, subject to the modifications suggested in this decision.

30. For this rate case cycle, PG&E shall report annually on the results of implementing and operating the economic dispatch option and submit the option to annual review. This report and review shall take place in connection with the reasonableness phase of the Energy Cost Adjustment Clause (ECAC) proceeding.

31. PG&E is authorized to withdraw Schedule E-24.

32. PG&E is authorized to offer DRA's proposal for a new option, derived from Schedule E-25, as a new tariff designated as Schedule B-26.

33. PG&E is authorized to offer an experimental Schedule E-11, based on the proposal of the Association of California Water Agencies (ACWA), as modified by PG&E.

34. PG&E shall work with DRA in reviewing the initial results of the experimental Schedule A-RTP, before expanding the program in 1991.

35. PG&E shall revise its tariffs to apply the average rate limiter to all of a standby customer's regular service load, subject to the limitations described in this decision.

36. PG&E, as part of its next general rate case, shall submit a study of the costs of metering and obtaining the data needed to distinguish between the different types of standby service.

37. PG&E is authorized to withdraw the unconventional technology allowance of Schedule S.

38. PG&E is authorized to offer experimental Schedule ED subject to the limitations stated in this decision.

39. PG&E is authorized to eliminate the minimum bill for Schedules AG-5A, AG-5B, and AG-5C.

40. PG&E shall install the necessary time-of-use (TOU) meters by May 1, 1990 to allow current customers on Schedule AG-6 to convert to TOU schedules.

41. PG&E shall submit a report stating the number of agricultural TOU meters installed in 1989, the number of requests for conversion received in 1989, by month and by schedule, the backlog by schedule existing at the end of 1989, and the average delay in responding to a request for conversion. The report will be due on March 15, 1990, and shall be served on the California Farm Bureau Federation (CFBF), the Power Users Protection Council (PUPC), ACWA, DRA, and any other party making a specific request to PG&E.

42. PG&E's proposal to transfer the high pressure sodium vapor facilities served under Schedule LS-1, Class B, to Class A, is authorized.

43. PG&E shall continue to report on the progress of the voluntary TOU program as part of its annual ECAC cases.

44. PG&E shall continue to file an annual report, by no later than March 1, 1990, of its hazardous waste program and related expenditures.

45. PG&E shall file an advice letter, no later than October 1, 1990, to true-up test year 1990 ratemaking federal income tax expenses, consistent with D.89-11-058. The resulting difference in revenue requirement shall be included in PG&E's 1991 attrition adjustment.

46. The Petition of DRA to set aside submission and reopen the general rate case on the issue of an adjustment to account 925, relating to fallout-type particulate pollution claims is granted. The issue of Account 925 is reopened to permit all parties to submit updated information on all expenses included in Account 925. Funds authorized for Account 925 in this decision shall be subject

to refund funds authorized for Account 925 shall be subject to refund so that the Commission may conduct a further review as specified herein.

47. If PG&E receives a variance from the Regional Water Quality Control Board for its surface impoundment program, PG&E shall consult with DRA to identify other appropriate environmental-related uses for the amounts saved by the issuance of the variance.

48. PG&E shall report in its next general rate case application on the progress, costs and benefits of the 500 kV bare hand live-line training program.

49. In future general rate case and offset applications, PG&E shall show then current revenues by customer class for each revenue account in PG&E's preliminary statement. PG&E shall clearly segregate retail revenues for which the Commission sets rates from all other revenues. PG&E shall separately describe te revenue relief requested for retail customers and for all other customers.

50. Pacific Gas and Electric Company is authorized and directed to file with this Commission on or after the effective date of this order, and at least three days prior to their effective dated revised tariff schedules for gas rates derived from revenue changes as set forth in Appendixes such rates to be calculated as set forth in D.89-09-094.

51. The record in this proceeding shall remain open to take testimony on the specific issue of whether the adopted rates for customers served under Schedule AG-5 are competitive with alternative pumping fuels. This matter shall be decided before May 1, 1990.

52. PG&E and CACD shall conduct a joint study of the agricultural class' marginal costs and intraclass allocation and their implications for rate design. This study shall be completed by November 5, 1990, and served on the Commissioners, DRA, CFBF, PUPC, the assigned ALJs, and any other party requesting a copy.

53. PG&E is authorized $3,900,000 for the estimated costs of PG&E's share of the HVDC expansion project, subject to refund to account for reductions in PG&E's revenue requirements which may result from certain limited and specified issues: (1) if the final contract between PG&E and Edison or any agreement to lay off PG&E's share of the project result in net costs lower than authorized in this decision, or (2) if the Commission disallows any of Edison's costs in A.89-10-011.

This order is effective today.

Dated DEC 20 1989, 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/ G. MITCHELL WILK
President
/s/ FREDERICK R. DUDA
Commissioner
/s/ JOHN B. OHANIAN
Commissioner

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

Wesley Franklin

WESLEY FRANKLIN, Acting Executive Director

PB

ALJ/GLW/CACD/am/6

APPENDIX A

PACIFIC GAS & ELECTRIC COMPANY
Electric Department - CPUC Jurisdiction
Consolidated Revenue Changes

LINE	RATE ELEMENT	PRESENT RATE REVENUE 1/ ($000's)	REVENUE CHANGE ($000's)	CONSOLIDATED REVENUE ($000's)	AVERAGE RATE (cents/KWh)
1	General Rate Case Revenues 2/	3,143,808	44,209	3,188,017	4.725
2	Diablo Canyon Basic Revenue Requirement	216,943	(6,497)	210,446 3/	0.312
3	Other Operating Revenues	(21,183)	(25,211)	(46,394)	(0.069)
4	Discount Sales Revenues	(49,636)	49,636	0	0.000
5	SUBTOTAL	3,289,932	62,137	3,352,069	4.968
6	Estimated ERAM Balance on October 31, 1989	0	(283,830)	(283,830)	(0.421)
7	Low Income Discount	(21,370)	21,370	0	0.000
8	DSM/R&D Balancing Account Offset	0	(36,844)	(36,844)	(0.055)
9	SUBTOTAL - BASE ENERGY RATE REVENUES	3,268,562	(237,167)	3,031,395	4.493
10	Energy Cost Adjustment Clause (ECAC) 4/	2,520,045	622,936	3,142,981	4.525
11	ECAC Energy Discount Sales Revenues 4/	(56,723)	164	(56,559)	(2.844)
12	Annual Energy Rate (AER) 4/	158,534	26,629	185,163	0.267
13	AER Energy Discount Sales Revenues 4/	(5,610)	17	(5,593)	(0.281)
14	Diablo Canyon Adjustment Clause (DCAC)	0	0	0	0.000
15	Conservation Financing Adjustment (CFA)	1,351	0	1,351	0.002
16	CPUC Fees	8,091	0	8,091	0.012
17	SUBTOTAL	5,894,250	412,578	6,306,828	9.347
18	Discount Sales Revenues	0	(49,636)	(49,636)	(0.074)
19	TOTAL (for rate design purposes)	5,894,250	362,942	6,257,192	
20	Low Income Discounts	0	(26,516)	(26,516)	(0.039)
21	Low Income Surcharge	0	32,932	32,932	0.049
22	SUBTOTAL (Retail Revenue Requirement)	5,894,250	369,358	6,263,608	
23	Other Operating Revenues	21,183	25,211	46,394	0.069
24	Discount Sales Revenues	49,636	0	49,636	0.074
25	ECAC Energy Discount Sales Revenues 4/	56,723	(164)	56,559	0.084
26	AER Energy Discount Sales Revenues 4/	5,610	(17)	5,593	0.008
27	TOTAL COMPANY REVENUES	6,021,792	394,406	6,416,198	9.509

1/ At 69,464 gwh GRC sales, adjusted for Employee Discounts (63 gwh), Energy Discount Sales (1,989 gwh), and FERC Resale (316 gwh).
2/ Excludes Diablo Canyon and includes Other Operating and Discount Sales Revenues.
3/ Diablo Canyon Basic Revenue Requirement per D.88-12-083 Appendix C paragraph 7, D.89-11-068 and FF&U and CPUC jurisdictional factors adopted from this General Rate Case decision.
4/ Adopted revenues computed at the GRC sales forecast and average rate as adopted in A.89-04-001, D.89-12-015.

SUMMARY OF AUTHORIZED BASE REVENUES

Authorized Base Revenue Amount effective 1/1/90	$3,352,069
Authorized Base Revenue Amount effective 1/1/89	($3,209,610)
Authorized increase in Base Revenue Amount	142,459
% Increase in Base Rate Revenues	4.44%

(END OF APPENDIX A)

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
OPERATING REVENUES AT PRESENT RATES
Thousands Of 1990 Dollars
Test Year 1990

Description	Adopted
Residential	$2,314,664
Small & Medium Light and Power	2,224,751
Large Light and Power	988,520
Public Authority	30,119
Agricultural	280,981
Street Lighting	45,312
Railway	17,601
Interdepartmental	13,673
Sales to Ultimate Customers	$5,915,621
Other Operating Revenues	21,183
Discounted Sales Revenues	49,636
FERC	84,139
Total Operating Revenues	$6,070,579
Less: Non-General Revenues	2,911,665
Less: ERAM Revenue	17,993
General Rate Case Revenues	$3,140,921

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
CALCULATION OF FRANCHISE FEES AND UNCOLLECTIBLES
Thousands Of 1990 Dollars
Test Year 1990

Description	Adopted
At Present Rates	
Revenues at Current Rates	$6,070,579
Less: Interdepartmental	13,673
Revenues From Customers	$6,056,906
% Revenues From Customers	99.77%
General Rate Case Revenues	3,140,921
% Revenues From Customers	99.77%
Revenues From Customers	3,133,831
Uncollectibles Factor	0.00222
Uncollectibles	$6,957
Revenues From Customers	$3,133,831
Less Uncollectibles	6,957
Net Revenues From Customers	$3,126,874
Franchise Requirement Factor	0.006389
Franchise Requirements	$19,978
Less: Sacramento Franchise Amortization	465
Total Franchise Requirements	$19,513

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
TOTAL PRODUCTION OPERATION EXPENSE
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Description	Adopted
Operation	
Steam	$69,129
Nuclear	931
Hydraulic	20,006
Other	683
Total Operation	$90,749
Maintenance	
Steam	96,659
Nuclear	91
Hydraulic	19,557
Other	566
Total Maintenance	$116,873
TOTAL PRODUCTION (1987$)	$207,622
Escalation Amounts, 1987 to 1990	
Labor	10,093
Non-Labor	17,423
Other	0
Total	$27,517
TOTAL PRODUCTION (1990$)	$235,138

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
STEAM PRODUCTION EXPENSE
(Thousands of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Account No.	Description	Adopted
	Operation	
500.0	Supervision and Engineering	$4,535
501.0	Fuel Related Expenses	864
502.0	Steam Expenses	12,008
505.0	Electric Expenses	32,843
506.0	Misc. Steam Power Expenses	16,571
507.0	Rents	2,308
	Total Operation	$69,129
	Maintenance	
510.0	Supervision and Engineering	12,168
511.0	Structures	671
512.0	Boiler Plant	28,918
513.0	Electric Plant	47,874
514.0	Miscellaneous Steam Plant	7,028
	Total Maintenance	$96,659
	TOTAL STEAM PRODUCTION (1987$)	$165,788
	Escalation Amounts, 1987 to 1990	
	Labor	7,704
	Non-Labor	14,419
	Other	0
	Total	$22,124
	TOTAL STEAM PRODUCTION (1990$)	$187,912

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
NUCLEAR PRODUCTION EXPENSE
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Account No.	Description	Adopted
	Operation	
517.0	Supervision and Engineering	$191
519.0	Coolants and Water	16
520.0	Steam Expenses	165
523.0	Electric Expenses	45
524.0	Misc. Nuclear Power Expenses	514
	Total Operation	$931
	Maintenance	
528.0	Supervision and Engineering	0
529.0	Structures	16
530.0	Reactor Plant Equipment	67
531.0	Electric Plant	0
532.0	Miscellaneous Nuclear Plant	8
	Total Maintenance	$91
	TOTAL NUCLEAR PROD. (1987$)	$1,022
	Escalation Amounts, 1987 to 1990	
	Labor	51
	Non-Labor	84
	Other	0
	Total	$135
	TOTAL NUCLEAR PROD. (1990$)	$1,157

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
HYDRAULIC PRODUCTION EXPENSE
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Account No.	Description	Adopted
	Operation	
535.0	Supervision and Engineering	$1,821
537.0	Hydraulic Expenses	3,438
538.0	Electric Expense	5,508
539.0	Misc. Hydro Expense Generation	3,579
540.0	Rents	5,660
	Total Operation	$20,006
	Maintenance	
541.0	Supervision and Engineering	3,001
542.0	Structures	526
543.0	Reservoirs, Dams and Waterways	4,307
544.0	Maintenance of Electric Plant	8,843
545.0	Miscellaneous Hydraulic Plant	2,879
	Total Maintenance	$19,557
	TOTAL HYDRO PRODUCTION (1987$)	$39,563
	Escalation Amounts, 1987 to 1990	
	Labor	2,244
	Non-Labor	2,862
	Other	0
	Total	$5,107
	TOTAL HYDRO PRODUCTION (1990$)	$44,669

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
OTHER PRODUCTION EXPENSE
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Account No.	Description	Adopted
	Operation	
546.0	Supervision and Engineering	$79
548.0	Generation Expenses	401
549.0	Misc. Other Power Expenses	203
	Total Operation	$683
	Maintenance	
551.0	Supervision and Engineering	135
552.0	Maintenance of Structures	6
553.0	Maintenance of Electric Plant	163
554.0	Misc. Other Power Gen. Plant	262
	Total Maintenance	$566
	TOTAL OTHER PRODUCTION (1987$)	$1,249
	Escalation Amounts, 1987 to 1990	
	Labor	94
	Non-Labor	58
	Other	0
	Total	$152
	TOTAL OTHER PRODUCTION (1990$)	$1,401

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
TRANSMISSION OPERATION EXPENSE
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Account No.	Description	Adopted
	Operation	
560.0	Supervision and Engineering	$2,734
561.0	Load Dispatching	3,812
562.0	Station Expenses	10,709
563.0	Overhead Line Expenses	3,121
564.0	Underground Line Expenses	110
565.0	Trans. of Elect. By Others	5,765
566.0	Misc. Transmission Expenses	3,934
567.0	Rents	475
	Total Operation	$30,660
	Maintenance	
568.00	Supervision and Engineering	2,631
569.00	Structures	122
570.00	Station Equipment	9,886
571.00	Overhead Lines	10,012
572.00	Underground Lines	400
573.00	Misc. Transmission Plant	231
	Total Maintenance	$23,282
	TOTAL TRANSMISSION (1987$)	$53,942
	Escalation Amounts, 1987 to 1990	
	Labor	3,212
	Non-Labor	3,070
	Other	0
	Total	$6,283
	TOTAL TRANSMISSION (1990$)	$60,225

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
DISTRIBUTION OPERATION EXPENSE
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Account No.	Description	Adopted
	Operation	
580.0	Supervision and Engineering	$20,606
582.0	Station Expenses	12,246
583.0	Overhead Line Expenses	16,979
584.0	Underground Line Expenses	4,953
585.0	Street Lighting & Signal Sys.	1,981
586.0	Meter Expenses	23,995
587.0	Customer Installations	12,689
588.0	Misc. Distribution Expenses	42,413
589.0	Rents	175
	Total Operation	$136,037
	Maintenance	
590.00	Supervision and Engineering	13,762
591.00	Structures	73
592.00	Station Equipment	6,593
593.00	Overhead Services	88,367
594.00	Underground Lines	15,578
595.00	Line Transformers	9,107
596.00	Street Lighting & Signal Sys.	2,121
597.00	Meters	1,249
598.00	Misc. Distribution Plant	107
	Total Maintenance	$136,957
	TOTAL DISTRIBUTION (1987$)	$272,994
	Escalation Amounts, 1987 to 1990	
	Labor	15,624
	Non-Labor	19,556
	Other	0
	Total	$35,180
	TOTAL DISTRIBUTION (1990$)	$308,174

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
CUSTOMER ACCOUNTS EXPENSE
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Account No.	Description	Adopted
901.0	Supervision	$4,368
902.0	Meter Reading Expenses	19,165
903.0	Customer Records and Collectibles	63,553
904.0	Uncollectible Accounts	6,957
905.0	Misc. Customer Accounts Exp.	9,885
	TOTAL CUSTOMER ACCTS. (1987$)	$103,928
	Total (Less Uncollectibles)	$96,971
	Escalation Amounts, 1987 to 1990	
	Labor	7,887
	Non-Labor	2,427
	Other	0
	Total	$10,314
	TOTAL CUSTOMER ACCTS. (1990$)	$114,242
	Total (Less Uncollectibles)	$107,285

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
DEMAND-SIDE MANAGEMENT EXPENSE
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Account No.	Description	Adopted
	Residential & Non-Residential Conservation, Service Planning, Tariff Administration, and Load Management Expenses	
907.0	Supervision	$3,056
908.0	Customer Assistance Expense	83,691
909.0	Informational & Instruct. Exp.	1,802
910.0	Miscellaneous	11,404
	TOTAL DEMAND-SIDE MANAGEMENT (1987$)	$99,953
	Escalation Amounts, 1987 to 1990	
	Labor	3,369
	Non-Labor	6,006
	Other	0
	Total	$9,375
	TOTAL DEMAND-SIDE MANAGEMENT (1990$)	$109,328

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
ADMINISTRATIVE & GENERAL EXPENSES
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Account No.	Description	Adopted
	Operation	
920.0	Administrative & Gen. Salaries	$99,382
921.0	Office Supplies and Expenses	30,477
922.0	Admin. & Gen. Transfer Credit	(23,764)
923.0	Outside Services Employed	11,223
924.0	Property Insurance	16,348
925.0	Injuries and Damages	35,776
926.0	Employee Pensions and Benefits	139,683
927.0	Franchise Requirements	19,513
928.0	Regulatory Commission Expenses	160
930.0	Other Misc. General Expenses	38,841
931.0	Rents	15,072
	Total Operation	$382,710
	Maintenance	
935.0	Maintenance of General Plant	2,719
	Total Maintenance	2,719
	TOTAL ADMIN. & GEN. (1987$)	$385,429
	Total (Less Franchise Req.)	$365,917
	Escalation Amounts, 1987 to 1990	
	Labor	17,084
	Non-Labor	11,176
	Other	0
	Total	$28,261
	TOTAL ADMIN. & GEN. (1990$)	$413,690
	Total (Less Franchise Req.)	$394,177

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
EXPENSE SUMMARY
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Description		Adopted
TOTAL NON-ESCALATED (1987$)		
Steam Production	$165,788	
Nuclear Production	1,022	
Hydraulic Production	39,563	
Other Production	1,249	
Total Production		$207,622
Transmission		53,942
Distribution		272,994
Customer Accounts		103,928
Demand-Side Management		99,953
Admin. and Gen. (incl. wage related)		385,429
Other Adjustments		(16,159)
Total Non-Escalated (1987$)		$1,107,710
TOTAL ESCALATED (1990$)		
Steam Production	187,912	
Nuclear Production	1,157	
Hydraulic Production	44,669	
Other Production	1,401	
Total Production		$235,138
Transmission		60,225
Distribution		308,174
Customer Accounts		114,242
Demand-Side Management		109,328
Admin. and Gen. (incl. wage related)		413,690
Other Adjustments		(17,504)
Total Escalated (1990$)		$1,223,293
TOTAL ESCALATION (1987$ to 1990$)		
Steam Production	22,124	
Nuclear Production	135	
Hydraulic Production	5,107	
Other Production	152	
Total Production		$27,517
Transmission		6,283
Distribution		35,180
Customer Accounts		10,314
Demand-Side Management		9,375
Admin. and Gen. (incl. wage related)		28,261
Other Adjustments		(1,345)
Total Escalation		$115,583

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
LABOR SUMMARY
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Description		Adopted
LABOR NON-ESCALATED (1987$)		
Steam Production	$71,674	
Nuclear Production	475	
Hydraulic Production	20,881	
Other Production	871	
Total Production		$93,901
Transmission		29,886
Distribution		145,352
Customer Accounts		73,377
Demand-Side Management		31,345
Admin. and Gen. (incl. wage related)		158,940
Other Adjustments		(12,515)
Total Non-Escalated Labor		$520,287
Labor Escalation Factor		1.10749
LABOR ESCALATED (1990$)		
Steam Production	79,378	
Nuclear Production	526	
Hydraulic Production	23,125	
Other Production	965	
Total Production		$103,994
Transmission		33,098
Distribution		160,976
Customer Accounts		81,264
Demand-Side Management		34,714
Administrative and General		176,024
Other Adjustments		(13,860)
Total Escalated Labor		$576,211
LABOR ESCALATION (1987$ to 1990$)		
Steam Production	7,704	
Nuclear Production	51	
Hydraulic Production	2,244	
Other Production	94	
Total Production		$10,093
Transmission		3,212
Distribution		15,624
Customer Accounts		7,887
Demand-Side Management		3,369
Administrative and General		17,084
Other Adjustments		(1,345)
Total Labor Escalation		$55,925

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
NON LABOR SUMMARY
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Description		Adopted
NON-LABOR NON-ESCALATED (1987$)		
Steam Production	$94,114	
Nuclear Production	547	
Hydraulic Production	18,682	
Other Production	378	
Total Production		$113,721
Transmission		20,038
Distribution		127,642
Customer Accounts		15,838
Demand-Side Management		39,199
Administrative and General		72,947
Other Adjustments		0
Total Non-Escalated Non-Labor		$389,384
Non-Labor Escalation Factor		1.15321
NON-LABOR ESCALATED (1990$)		
Steam Production	108,533	
Nuclear Production	631	
Hydraulic Production	21,544	
Other Production	436	
Total Production		$131,144
Transmission		23,108
Distribution		147,198
Customer Accounts		18,265
Demand-Side Management		45,205
Administrative and General		84,123
Other Adjustments		0
Total Escalated Non-Labor		$449,043
NON-LABOR ESCALATION (1987$ to 1990$)		
Steam Production	14,419	
Nuclear Production	84	
Hydraulic Production	2,862	
Other Production	58	
Total Production		$17,423
Transmission		3,070
Distribution		19,556
Customer Accounts		2,427
Demand-Side Management		6,006
Administrative and General		11,176
Other Adjustments		0
Total Non-Labor Escalation		$59,658

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
OTHER SUMMARY
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Description		Adopted
OTHER NON-ESCALATED (1987$)		
Steam Production	$0	
Nuclear Production	0	
Hydraulic Production	0	
Other Production	0	
Total Production		$0
Transmission		4,018
Distribution		0
Customer Accounts		14,713
Customer Service & Informational		29,409
Administrative and General		153,543
Other Adjustments		(3,644)
Total Non-Escalated Other		$198,039
Other Escalation Factor		1.0000
OTHER ESCALATED (1990$)		
Steam Production	0	
Nuclear Production	0	
Hydraulic Production	0	
Other Production	0	
Total Production		$0
Transmission		4,018
Distribution		0
Customer Accounts		14,713
Demand-Side Management		29,409
Administrative and General		153,543
Other Adjustments		(3,644)
Total Escalated Other		$198,039
OTHER ESCALATION (1987$ to 1990$)		
Steam Production	0	
Nuclear Production	0	
Hydraulic Production	0	
Other Production	0	
Total Production		$0
Transmission		0
Distribution		0
Customer Accounts		0
Demand-Side Management		0
Administrative and General		0
Other Adjustments		0
Total Other Escalation		$0

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
TAXES OTHER THAN ON INCOME
Thousands Of 1990 Dollars
Test Year 1990

Description	Adopted
Ad Valorem Taxes	
Ca., Ariz., N.M., Nev.	$97,091
Total Ad Valorem Taxes	97,091
Payroll Taxes	
Federal Insurance Contrib. Act	37,982
Federal Unemployment Insurance	693
State Unemployment Insurance	951
San Francisco Payroll Expense Tax	2,629
Total Payroll Taxes	42,254
Miscellaneous Taxes	
Business and Other Taxes	5,073
Total Miscellaneous Taxes	5,073
Total Taxes OTOI	$144,418

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
INCOME TAX ADJUSTMENTS
Thousands Of 1990 Dollars
Test Year 1990

Description	Adopted
California Income Tax Adjustments	
CCFT Depreciation	$423,657
Fiscal/Calendar Adjustment	1,764
Interest Charges	347,647
Operating Expense Adjustment	(745)
Capitalized Interest Adjustment	(17,168)
Ad Valorem Taxes Capitalized	112
Use Tax Capitalized	0
Removal Costs	17,544
Vacation Accrual Reduction	(4,255)
Repair Allowance	37,489
Capitalized Pension and Benefits	3,271
	$809,317
Federal Income Tax Adjustments	
FIT Depreciation	348,700
Fiscal/Calendar Adjustment	1,764
Interest Charges	347,647
Operating Expense Adjustment	(745)
Capitalized Interest Adjustment	(17,168)
Ad Valorem Taxes Capitalized	112
Removal Costs	17,544
Vacation Accrual Reduction	(4,255)
Repair Allowance	27,000
Capitalized Pension and Benefits	3,271
Preferred Dividend Credit	3,507
	$727,377

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
TAXES ON INCOME
Thousands Of 1990 Dollars
Test Year 1990

Description	Adopted
California Corporation Franchise Tax	
Operating Revenues	$3,140,921
Operating Expenses	1,225,968
Qualified Nuclear Decommissioning Exp.	64,761
Taxes Other Than On Income	144,418
Income Tax Adjustments	809,317
Superfund tax	1,074
California Taxable Income	$895,383
CCFT Tax Rate	9.30%
Current CCFT	$83,271
CCFT CREDITS	
Defense Facilities Credit	(114)
Deferred Taxes - Other	52
Deferred Taxes - Interest	(1,597)
Deferred Taxes - Vacation	(397)
TOTAL CCFT	$81,215
Federal Income Tax	
Operating Revenues	$3,140,921
Operating Expenses	1,225,968
Qualified Nuclear Decommissioning Exp.	64,761
Taxes Other Than On Income	144,418
CCFT	83,271
Income Tax Adjustments	727,377
Superfund tax	1,074
Federal Taxable Income	$894,052
FIT Tax Rate	34.00%
Federal Income Tax	$303,978
Flowback of Excess Def'rd Taxes	(1,208)
Defense Facilities Credit	(1,087)
Deferred Taxes - Other	(1,573)
Deferred Taxes - Interest	(5,294)
Deferred Taxes - Vacation	(1,312)
FIT Before Adjustments	$293,504
Less: Investment Tax Credit	84
FIT Before Adjustments	$293,420

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
DEPRECIATION AND NUCLEAR DECOMMISSIONING EXPENSE
Thousands Of 1990 Dollars
Test Year 1990

Description	Adopted
Steam Production	$99,213
Nuclear Production	0
Hydraulic Production	37,872
Other Production	4,470
Transmission	57,609
Distribution	262,245
General and Common Plant	62,630
Experimental Plant	0
Total Depreciation Expense	524,038
Nuclear Decommissioning Expense	
Qualified	
Diablo Unit 1	$24,285
Diablo Unit 2	30,189
Humbolt Unit 3 (50%)	10,287
Sub Total	$64,761
Nonqualified	
Humbolt Unit 3 (50%)	10,287
Total Nuclear Decommissioning Expense	$75,048

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
DEPRECIATION RESERVE
Thousands Of 1990 Dollars
Test Year 1990

Description	Adopted
Depreciation Reserve - EOY	
Steam Production	$1,047,737
Nuclear Production	0
Hydraulic Production	471,000
Other Production	27,980
Transmission	652,962
Distribution	2,215,551
General and Common Plant	410,560
Depreciation Reserve - BOY	$4,825,790
Other Adjustments (excl. Depr. expense)	
Steam Production	16,858
Nuclear Production	0
Hydraulic Production	712
Other Production	0
Transmission	2,411
Distribution	41,096
General and Common Plant	(11,434)
Other Adjustments (excl. depr.)	49,643
Depreciation Reserve - EOY	
Steam Production	1,130,092
Nuclear Production	0
Hydraulic Production	508,160
Other Production	32,450
Transmission	708,160
Distribution	2,436,700
General and Common Plant	484,624
Depreciation Reserve - EOY	5,300,185
Depreciation Reserve - Wtd. avg.	$5,062,988

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
PLANT IN SERVICE - EOY
Thousands Of 1990 Dollars
Test Year 1990

Description	Adopted
Plant in Service - BOY	
Intangible	$34,123
Production Plant	
Steam	2,367,391
Nuclear	0
Hydraulic	1,850,970
Other Production	68,839
Total Production	$4,287,200
Transmission Plant	1,746,581
Distribution Plant	6,042,989
General and Common Plant	1,106,560
Diablo Canyon Adjustment	0
Total Plant in Service : BOY	$13,217,453
Plant in Service - Net Additions	
Intangible	$4,476
Production Plant	
Steam	76,497
Nuclear	0
Hydraulic	90,288
Other Production	3,368
Total Production	$170,153
Transmission Plant	99,109
Distribution Plant	435,605
General and Common Plant	145,084
Diablo Canyon Adjustment	0
Total Net Additions	$854,427
Plant in Service - EOY	
Intangible	$38,599
Production Plant	
Steam	2,443,888
Nuclear	0
Hydraulic	1,941,258
Other Production	72,207
Total Production	$4,457,353
Transmission Plant	1,845,690
Distribution Plant	6,478,594
General and Common Plant	1,251,644
Diablo Canyon Adjustment	0
Total Plant in Service : EOY	$14,071,880

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
PLANT IN SERVICE - WTD. AVG.
Thousands Of 1990 Dollars
Test Year 1990

Description	Adopted
Plant in Service - BOY	
Intangible	$34,123
Production Plant	
Steam	2,367,391
Nuclear	0
Hydraulic	1,850,970
Other Production	68,839
Total Production	$4,287,200
Transmission Plant	1,746,581
Distribution Plant	6,042,989
General Plant	1,106,560
Diablo Canyon Adjustment	0
Total Plant in Service : BOY	$13,217,453
Plant in Service - Weighted Average Net Additions	
Intangible	$2,500
Production Plant	
Steam	19,339
Nuclear	0
Hydraulic	61,682
Other Production	1,628
Total Production	$82,649
Transmission Plant	38,725
Distribution Plant	217,153
General and Common Plant	56,795
Diablo Canyon Adjustment	0
Total Wtd. Avg. Net Additions	$397,822
Total Plant in Service - Weighted Average	
13635112 Intangible	$36,623
Production Plant	
Steam	2,386,730
Nuclear	0
Hydraulic	1,912,652
Other Production	70,467
Total Production	$4,369,849
Transmission Plant	1,785,306
Distribution Plant	6,260,142
General Plant	1,163,355
Diablo Canyon Adjustment	0
Total Plant in Service : Wtd. Avg.	$13,613,275

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
WEIGHTED AVERAGE DEPRECIATED RATE BASE
Thousands Of 1990 Dollars
Test Year 1990

Description	Adopted
FIXED CAPITAL @ BEGINNING OF YEAR	
Plant in Service	$13,217,453
PHFU	7,538
Total Fixed Capital - BOY	$13,224,991
WTD. AVG. NET ADDITIONS	
Plant in Service	397,822
PHFU	0
Total Wtd. Avg. Additions	$397,822
Tot. Wtd. Avg. Fixed Capital	$13,622,813
TAX REFORM ACT DEFERRALS	
Capitalized Interest	16,326
Vac Pay Deferrals	26,355
CIAC Deferral	19,459
Total Tax Reform Act Deferrals	$62,140
ADJUSTMENTS	
Cust. Adv. for Construction	(97,459)
Total Adjustments	($97,459)
WORKING CAPITAL	
Fuel Stock - Coal / Misc.	0
Materials & Supplies	66,047
Working Cash	82,273
Total Working Capital	$148,320
Tot. Before Ded. for Reserves	$13,735,814
DEDUCTIONS FOR RESERVES	
Wtd. Avg. Depreciation Reserve	5,062,988
Taxes Def. - Defense	10,003
Taxes Def. - ACRS	506,548
Taxes Def. - Ref. Ret. Debt	(6,832)
Deferred ITC	225,951
Total Ded. for Reserves	$5,798,657
Weighted Average Depreciated Rate Base	$7,937,157

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
DETERMINATION OF AVERAGE AMOUNTS OF WORKING
CASH CAPITAL SUPPLIED BY INVESTORS
Thousands Of 1990 Dollars
Test Year 1990

Description	Adopted
Operational Cash Requirements	
Cash	$37,440
Special Deposits & Working Funds	4,058
Other Receivables	29,219
Prepayments	10,721
Deferred Debits, Company-Wide	4,166
Total	$85,604
Less: Amounts Not Supplied By Investors	
Accrued Vacation & Empl. Witholdings	88,522
Credit recd. for capitlized supplies	22,033
Total	$110,555
Subtotal, Total Company	($24,951)
Electric Department Allocation Percentag	66.73%
Electric Department Allocation	(16,650)
Franchise Fee Amortization	(1,104)
Prepayments - Electric Department	1,005
Total Operational Cash Requirement	($16,749)
Plus: Average Amount Required	
Avg. Amt. Req. as a Result of Paying Expenses in Advance of Collecting Revenues	99,021
Total	$99,021
Average Net Amount of Working Cash Capital Supplied by Investors	$82,273

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
DEVELOPMENT OF AVERAGE LAG IN PAYMENT OF EXPESES
Thousands Of 1990 Dollars
Test Year 1990

Description	Expense	Average Lag Days	Product
	(A)	(B)	(C=AxB)
Fuel Oil	13,848	14.91	206474
Geothermal Steam	127,054	25.21	3203031
Natural Gas Purchas	220,914	37.08	8191491
Nuclear Fuel	0	70.63	0
Fed. Income Tax	$343,367	98.96	33979603
Purchased Power	1,341,820	47.29	63454668
Ad Val.Tax - CA	97,091	43.74	4246758
Payroll	561,521	14.20	7973602
Franchise Requireme	31,240	255.41	7979054
Goods and Services	385,737	32.94	12706175
Pension Expense	49,874	-3.92	-195507
S.F. Payroll Tax	2,629	137.37	361093
FICA Tax	37,982	6.64	252200
Fed. Unemp. Tax	693	73.93	51245
State Unemp. Tax	951	75.66	71927
Group Life Insuranc	7,002	-18.84	-131925
State Crp Frnch Tax	94,939	80.33	7626425
Depreciation	524,038	0.00	0
Materls From Store	150,754	0.00	0
Insurance and Casua	52,124	18.84	982016
Income Taxes, Defer	39,986	0.00	0
Abandoned Project	24	0.00	0
Savings Fund Plan	11,842	0.00	0
Health Vision & Den	60,740	8.21	498674
Adj. to ERTA Tax Ba	(52,432)	98.96	-5188662
TOTAL	4,103,739		146,268,342

Exp. Lag Days	35.64	= (C)/(A)
Revenue Lag Days	44.45	
Adj. to Rate Bas	99,021	
Rate Base Factor	7,838,135	
New Rate Base	$7,937,157	

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
SUMMARY OF EARNINGS AT ADOPTED PRESENT RATE
REVENUES AND EXPENSES
(Thousands Of 1990 Dollars Unless Otherwise Indicated)
Test Year 1990

Description	Adopted
Operating Revenues	
Revenues	$3,140,921
Total Operating Revenues	$3,140,921
Operating Expenses	
Production	207,622
Transmission	53,942
Distribution	272,994
Customer Accounts	96,971
Uncollectibles	6,957
Demand-Side Management	99,953
Administrative & General	365,917
Franchise Requirements	19,513
Other Adjustments	(16,159)
Subtotal (1987 Dollars)	$1,107,710
Labor Escalation Amount	55,925
Non-Labor Escalation Amount	59,658
Subtotal (1990 Dollars)	$1,223,293
Energy Cost	2,651
Project Amortization	24
Depreciation	524,038
Nuclear Decommissioning Exp.	75,048
Taxes Other Than On Income	144,418
Superfund tax	1,074
CA Corporation Franchise Tax	81,215
Federal Income Tax	293,420
Total Operating Expenses	$2,345,181
Net Operating Income	$795,740
Rate Base	7,937,157
Rate of Return (Total System)	10.03%

PACIFIC GAS AND ELECTRIC COMPANY
Electric Deprt.- CPUC Jurisdiction (Excl. Diablo Canyon)
SUMMARY OF EARNINGS AT ADOPTED PRESENT RATE
REVENUES AND EXPENSES
(Thousands Of 1990 Dollars Unless Otherwise Indicated)
Test Year 1990

Description	Jurisdictional Factors	Adopted
Operating Revenues		
Revenues	0.9753	$3,063,486
Total Operating Revenues		3,063,486
Operating Expenses		
Production	0.9945	206,480
Transmission	0.8805	47,498
Distribution	0.9839	268,596
Customer Accounts	0.9987	96,849
Uncollectibles		6,786
Demand-Side Management	1.0000	99,953
Administrative & Gen.	0.9819	359,301
Franchise Requirements		19,020
Other Adjustments	1.0000	(16,159)
Subtotal (1987 Dollars)		$1,088,324
Labor Escalation Amount	0.9819	54,915
Non-Labor Escl. Amount	0.9835	58,676
Subtotal (1990 Dollars)		$1,201,915
Energy Cost	0.0358	95
Project Amortization	0.9932	24
Depreciation	0.9748	510,833
Nuclear Decommissioning	0.9941	74,605
Taxes Other Than On Inc	0.9756	140,901
Superfund tax		1,020
CA Corporation Franchis	0.9646	78,339
Federal Income Tax	0.9679	284,001
Total Operating Expenses		$2,291,732
Net Operating Income		$771,754
Rate Base	0.9720	7,715,152
Rate of Return		10.00%
Auth. Rate of Return (CPUC Jurisdiction)		10.96%
Net-to-Gross multiplier :		1.68679
Authorized incr. in Revenues :		$124,531

PACIFIC GAS AND ELECTRIC COMPANY
Electric Deprt.- CPUC Jurisdiction (Excl. Diablo Canyon)
ADOPTED SUMMARY OF EARNINGS
(Thousands Of 1990 Dollars Unless Otherwise Indicated)
Test Year 1990

Description	Adopted
Operating Revenues	
Adopted Present Rate Revenues	$3,063,486
Authorized incr. in Revenues	124,531
Total Operating Revenues	$3,188,017
Operating Expenses	
Production	233,845
Transmission	53,030
Distribution	303,209
Customer Accounts	107,150
Uncollectibles	7,061
Demand-Side Management	109,328
Administrative & Gen.	387,051
Franchise Requirements	19,812
Other Adjustments	(17,504)
Subtotal (1990 Dollars)	$1,202,983
Energy Cost	95
Project Amortization	24
Depreciation	510,833
Nuclear Decommissioning Exp.	74,605
Taxes Other Than On Income	140,901
Superfund tax	1,154
CA Corporation Franchise Tax	89,809
Federal Income Tax	322,033
Total Operating Expenses	$2,342,436
Net Operating Income	$845,581
Rate Base	7,715,152
Rate of Return	10.96%

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
DEVELOPMENT OF THE NET-TO-GROSS MULTIPLIER
Test Year 1990

Description	(A)	(B)	(C=A*B)
Gross Operating Revenues			1.000000
Less: Uncoll.	0.002220	0.997743	0.002215
			0.997785
Less: Franchise	0.006389	0.995528	0.006360
			0.991425
Less: Super Fund	0.001200	0.898244	0.001078
			0.990347
Less: S.I.T.	0.093000	0.990347	0.092102
			0.898244
Less: F.I.T.	0.340000	0.898244	0.305403
Net Operating Revenues			0.592841
Uncoll. & F.F. Factor			1.008650
Superfund, State & Fed. Tax Factor			1.672327
N-T-G Multiplier			1.686792

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department
ESCALATION FACTORS - Total Company
COST OF CAPITAL - CPUC Jurisdiction
Test Year 1990

Description		Adopted
LABOR ------------>	1988	2.750%
ESCALATION FACTORS	1989	2.750%
	1990	4.900%
	1991	4.200%
	1992	4.800%
NON-LABOR -------->	1988	5.170%
ESCALATION FACTORS	1989	4.600%
	1990	4.830%
	1991	5.270%
	1992	5.460%
OTHER ------------>	ALL YEARS	0.000%
COMPOSITE ESCALATION FACTORS		
LABOR	1987 TO 1990	10.749%
NON-LABOR	1987 TO 1990	15.321%
OTHER	1987 TO 1990	0.000%

	COST	CAPITALIZATION	WTD. COST
Debt	9.32%	47.00%	4.38%
Pref. Stock	8.79%	6.25%	0.55%
Common equity	12.90%	46.75%	6.03%
Auth. Return on Rate Base (CPUC Jurisdiction) :			10.96%

(END OF APPENDIX B)

ATTRITION YEAR 1991

	Expenses for AY1991 in 000's of 1990$	Expenses for AY1991 in 000's of 1990$ (Calif.)	Transfer of Other Expenses to Labor/ Non-Labor	Expenses for AY1991 in 000's of 1990$ for Attrition purposes
	A D O P T E D	I N	G R C	
Production (Juris. Alloc. Factor =			0.9945	
Labor	103,994	103,422	0	103,422
Non Labor	131,144	130,423	0	130,423
Other	0	0	0	0
	235,138	233,845	0	233,845
Transmission (Juris. Alloc. Factor =			0.8805	
Labor	33,098	29,144	0	29,144
Non Labor	23,108	20,348	0	20,348
Other	4,018	3,538	0	3,538
	60,225	53,030	0	53,030
Distribution (Juris. Alloc. Factor =			0.9839	
Labor	160,976	158,383	0	158,383
Non Labor	147,198	144,826	0	144,826
Other	0	0	0	0
	308,174	303,209	0	303,209
Customer Accounts (Juris. Alloc. Factor			0.9987	
Labor	81,264	81,162	0	81,162
Non Labor	18,265	18,242	0	18,242
Other	14,713	14,808	0	14,808
	114,242	114,211	0	114,211
Demand-Side Mgmt (Juris. Alloc. Factor			1.0000)	
Labor	34,714	34,714	0	34,714
Non Labor	45,205	45,205	0	45,205
Other	29,409	29,409	0	29,409
	109,328	109,328	0	109,328
Admin. & Gen. (Juris. Alloc. Factor =			0.9819	
Labor	176,024	172,842	65,636	238,478
Non Labor	84,123	82,602	65,970	148,572
Other	153,543	151,419	(131,607)	19,812
	413,690	406,863	0	406,863

	Expenses for AY1991 in 000's of 1990$	Expenses for AY1991 in 000's of 1990$ (Calif.)	Transfer of Other Expenses to Labor/ Non-Labor	Expenses for AY1991 in 000's of 1990$ for Attrition purposes
	ADOPTED IN GRC			
Other Adjustments (Juris. Alloc. Factor			1.0000	
Labor	(13,860)	(13,860)	0	(13,860)
Non Labor	0	0	0	0
Other	(3,644)	(3,644)	0	(3,644)
	(17,504)	(17,504)	0	(17,504)
TOTAL O&M EXPENSES				
Labor	576,211	565,807	65,636	631,444
Non Labor	449,043	441,646	65,970	507,616
Other	198,039	195,530	(131,607)	63,923
	1,223,293	1,202,983	0	1,202,983

Labor Base for AY 1991 in 1990$ (Adopted in GRC)	$631,444
1990 Labor Escalation (estimated in GRC)	4.90%
1989 Labor Escalation (estimated in GRC)	2.75%
1988 Labor Escalation (estimated in GRC)	2.75%
1988 Labor Escalation (use recorded)	2.75%
1989 Labor Escalation (use recorded)	2.75%
1990 Labor Escalation (use updated estimate)	4.90%
1991 Labor Escalation (use updated estimate)	4.20%
Labor Base for AY 1991 in 1991$	657,965
Labor Escalation for AY 1991 in 1991$	26,521
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.008650
Increase in Revenue Requirement	26,750
Non-Labor Base for AY 1991 in 1990$ (Adopted in GRC)	507,616
1990 Non-Labor Escalation (estimated in GRC)	4.83%
1989 Non-Labor Escalation (estimated in GRC)	4.60%
1988 Non-Labor Escalation (estimated in GRC)	5.17%
1988 Non-Labor Escalation (recorded)	5.17%
1989 Non-Labor Escalation (recorded)	4.60%
1990 Non-Labor Escalation (use updated estimate)	4.83%
1991 Non-Labor Escalation (use updated estimate)	5.27%
Non-Labor Base for AY 1991 in 1991$	534,367

Non-Labor Escalation for AY 1991 in 1991$		26,751
Uncoll. & Franchise Fee Factor (Adopted in GRC)		1.008650
Increase in Revenue Requirement		26,983

Depreciation Exp. (Juris. Alloc. Factor 0.9748)

System avg. Depreciation Rate (Adopted in GRC)		3.8489%
Increase in Wtd. Avg. Plant in Service for AY1991 (Adopted in GRC)		844,505
Increase in Depreciation expense		32,504
Increase in Depreciation expense (Calif.)		31,685
Net-to-Gross Multiplier (Adopted in GRC)		1.686792
Increase in Revenue Requirement		53,446

Ad Valorem Taxes (Juris. Alloc. Factor 0.9756)

System avg. Ad Valorem Tax Rate (Adopted in GRC)		0.6900%
Increase in AY1991 EOY Plant in Service from TY1990 EOY Plant in Service (Adopted in GRC)		833,117
Increase in Ad Valorem Taxes		5,748
Increase in Ad Valorem Taxes (Calif.)		5,608
Uncoll. & Franchise Fee Factor (Adopted in GRC)		1.008650
Increase in Revenue Requirement		5,657

State Tax Depr. (Juris. Alloc. Factor = 0.9646)

State Tax Depr. Rte (Adopted in GRC)		3.0107%
Increase in AY1991 EOY Plant in Service from TY1990 EOY Plant in Service (Adopted in GRC)		833,117
Increase in State Tax Depreciation		25,082
Increase in State Tax Depreciation (Calif.)		24,194
Increase in CCFT (Tax Rate =	9.30%	(2,250)
Increase in FIT (Tax Rate =	34.00%	765
Increase in State & Federal Taxes		(1,485)
Net-to-Gross Multiplier (Adopted in GRC)		1.686792
Increase in Revenue Requirement		(2,505)

Federal Tax Depr. (Juris. Alloc. Factor .9679)		
Federal Tax Depr. Rate (Adopted in GRC)		2.4780%
Increase in AY1991 EOY Plant in Service from TY1990 EOY Plant in Service (Adopted in GRC)		833,117
Increase in Federal Tax Depreciation		20,645
Increase in Federal Tax Depreciation (Calif.)		19,982
Increase in Federal Taxes (Tax Rate	34.00%	(6,794)
Net-to-Gross Multiplier (Adopted in GRC)		1.686792
Increase in Revenue Requirement		(11,460)

Rate Base (Juris. Alloc. Factor = 0.9720)	
Wtd. avg. Depr Rate Base for TY1990 (Adopted in GRC)	7,937,157
Plant in Service (Adopted in GRC)	
Wtd. avg. Additions for TY1990	(397,822)
Net Additions for TY1990	854,427
Wtd. avg. Additions for AY1991	387,900
Plant Held for Future Use (Adopted in GRC)	
Wtd. avg. Additions for TY1990	0
Net Additionsfor TY1990	0
Wtd. avg. Additions for AY1991	(3,091)
Depreciation Reserve (Adopted in GRC)	
Wtd. avg. Depreciation Reserve for TY1990	5,062,988
Wtd. avg. Depreciation Reserve for AY1991	(5,552,096)
Taxes Deferred - ACRS (Adopted in GRC)	
Wtd. avg. Deferred Taxes - ACRS for TY1990	506,548
Wtd. avg. Deferred Taxes - ACRS for AY1991	(572,838)
Deferred ITC (Adopted in GRC)	
Wtd. Avg. Deferred ITC for TY1990	225,951
Wtd. Avg. Deferred ITC for AY1991	(218,751)
Wtd. avg. Depr Rate Base for AY1991	8,230,372
Wtd. avg. Depr. Rate Base in TY1990 (Adopted in GRC)	7,937,157
Wtd. avg. Depr. Rate Base in AY1991 (Adopted in GRC)	8,230,372
Wtd. avg. Depr. Rate Base in TY 1990 (Calif.)	7,715,152
Wtd. avg. Depr. Rate Base in AY 1991 (Calif.)	8,000,167

Long-term Debt

Return on Debt in TY 1990 (Adopted in GRC)	9.32%
Debt capitalization in TY 1990 (Adopted in GRC)	47.00%
Wtd. cost of Debt for Test Year 1990	4.38%
Return on Debt in AY 1991 (Adopted in AY1991)	9.32%
Debt capitalization in AY 1991 (Adopted in AY1991)	47.00%
Wtd. cost of Debt for Attrition Year 1991	4.38%
Increase in Debt cost in Attrition Year 1991	12,484
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.008650
Increase in Revenue Requirement	12,592

Preferred Stock

Return on Pref. Stock in TY 1990 (Adopted in GRC)	8.79%
Pref.Stk. capitalization in TY1990 (Adopted in GRC)	6.25%
Wtd. cost of Preferred Stock for Test Year 1990	0.55%
Return on Pref. Stock in AY1991 (Adopted in AY1991)	8.79%
Pref.Stk. capitalization AY1991 (Adopted in AY1991)	6.25%
Wtd. cost of Preferred Stock for Att. Year 1991	0.55%
Increase in Pref. Stock cost in Att. Year 1991	1,568
Net-to-Gross Multiplier (Adopted in GRC)	1.686792
Increase in Revenue Requirement	2,644

Common Equity

Return on Common Equity in TY 1990 (Adopted in GRC)	12.90%
Com. Equity capitalization TY 1990 (Adopted in GRC)	46.75%
Wtd. cost of Common Equity for Test Year 1990	6.03%
Return on Common Equity AY 1991 (Adopted in AY1991)	12.90%
Com. Eq. capitalization AY 1991 (Adopted in AY1991)	46.75%
Wtd. cost of Common Equity for Att. Year 1991	6.03%
Increase in Common Equity cost in Att. Year 1991	17,186
Net-to-Gross Multiplier (Adopted in GRC)	1.686792
Increase in Revenue Requirement	28,990

RATEBASE TRACKING

Wtd. avg. Depr.RateBase in TY1990 (Adopted in GRC)	7,937,157
Wtd. avg. Depr.RateBase in TY1990 (use updated est.)	7,937,157
Wtd. avg. Depr.RateBase in AY1991 (Adopted in GRC)	8,230,372
Wtd. avg. Depr.RateBase in AY1991 (use updated est.)	8,230,372

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
REVENUE REQUIREMENTS FOR ATTRITION YEAR 1991
Thousands Of 1991$

ITEM	ATTRITION YEAR 1991
O & M EXPENSES :	
Labor Escalation	$26,750
Non-Labor Escalation	26,983
Total O&M Expenses	53,733
CAPITAL RELATED ITEMS :	
Book Depreciation Expenses	53,446
Ad Valorem Taxes	5,657
State Tax Depreciation	(2,505)
Federal Tax Depreciation	(11,460)
Debt cost	12,592
Preferred Stock cost	2,644
Common Equity cost	28,990
Total Capital Related Items	89,364
OTHER AUTHORIZED ITEMS :	
Humboldt Nuclear Decommissioning	(13,821)
Abandoned Project Amortization Adjustment	(24)
Non-recurring O&M Adjustment	0
SMUD Discounted Sales Adjustment	(2,400)
Total Other Authorized Items	(16,245)
ADD'L REVENUE REQUIREMENTS ---->	$126,852
Exclude % attributable to Large Light & Power (To be adopted in OIR 86-10-001)	0.00%
TOTAL ADD'L REVENUE REQUIREMENTS ---->	126,852

ATTRITION YEAR 1992

Labor Base

Total Labor Base for AY 1992 in 1991$	657,965
1991 Labor Escalation (estimated in GRC)	4.20%
1990 Labor Escalation (estimated in AY1989)	4.90%
1990 Labor Escalation (use recorded)	4.90%
1991 Labor Escalation (use updated estimate)	4.20%
1992 Labor Escalation (use updated estimate of CPI-Wage Earners)	4.80%
Labor Base for AY 1992 in 1992$	689,547
Labor Escalation for AY 1992 in 1992$	31,582
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.008650
Increase in Revenue Requirement	31,855

Non-Labor Base

Non-Labor Base for AY 1991 (Adopted in AY1991)	$534,367
1991 Non-Labor Escalation (estimated in GRC)	5.27%
1990 Non-Labor Escalation (estimated in AY1989)	4.83%
1990 Non-Labor Escalation (use recorded)	4.83%
1991 Non-Labor Escalation (use updated estimate)	5.27%
1992 Non-Labor Escalation (use updated estimate)	5.46%
Non-Labor Base for AY 1992 in 1992$	563,544
Non-Labor Escalation for AY 1992 in 1992$	29,176
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.008650
Increase in Revenue Requirement	29,429

Depreciation Exp. (Juris. Alloc. Factor 0.9748)

System avg. Depreciation Rate (Adopted in GRC)	3.8489%
Increase in Wtd. Avg. Plant in Service for AY1992 (Adopted in GRC)	853,205
Increase in Depreciation expense	32,839
Increase in Depreciation expense (Calif.)	32,011
Net-to-Gross Multiplier (Adopted in GRC)	1.686792
Increase in Revenue Requirement	53,997

Ad Valorem Taxes (Juris. Alloc. Factor 0.9756)		
System avg. Ad Valorem Tax Rate (Adopted in GRC)		0.6900%
Increase in AY1992 EOY Plant in Service from AY1991 EOY Plant in Service (Adopted in GRC)		876,261
Increase in Ad Valorem Taxes		6,046
Increase in Ad Valorem Taxes (Calif.)		5,899
Uncoll. & Franchise Fee Factor (Adopted in GRC)		1.008650
Increase in Revenue Requirement		5,950

State Tax Depr. (Juris. Alloc. Factor = 0.9646)		
State Tax Depr. Rate (Adopted in GRC)		3.0107%
Increase in AY1992 EOY Plant in Service from AY1991 EOY Plant in Service (Adopted in GRC)		876,261
Increase in State Tax Depreciation		26,381
Increase in State Tax Depreciation (Calif.)		25,447
Increase in CCFT (Tax Rate =	9.30%	(2,367)
Increase in FIT (Tax Rate =	34.00%	805
Increase in State & Federal Taxes		(1,562)
Net-to-Gross Multiplier (Adopted in GRC)		1.686792
Increase in Revenue Requirement		(2,635)

Federal Tax Depr. (Juris. Alloc. Factor 0.9679)		
Federal Tax Depr. Rate (Adopted in GRC)		2.4780%
Increase in AY1992 EOY Plant in Service from AY1991 EOY Plant in Service (Adopted in GRC)		876,261
Increase in Federal Tax Depreciation		21,714
Increase in Federal Tax Depreciation (Calif.)		21,017
Increase in Federal Taxes (Tax Rate	34.00%	(7,146)
Net-to-Gross Multiplier (Adopted in GRC)		1.686792
Increase in Revenue Requirement		(12,053)

Rate Base (Juris. Alloc. Factor = 0.9720)

Wtd. avg. Depr Rate Base for AY1991 (Adopted in GRC)	8,230,372
Plant in Service (Adopted in GRC)	
Wtd. avg. Additions for AY1991	(387,900)
Net Additions for AY1991	833,117
Wtd. avg. Additions for AY1992	407,988
Plant Held for Future Use (Adopted in GRC)	
Wtd. avg. Additions for TY1991	3,091
Net Additions for TY1991	(3,258)
Wtd. avg. Additions for AY1992	0
Depreciation Reserve (Adopted in GRC)	
Wtd. avg. Depreciation Reserve for AY1991	5,552,096
Wtd. avg. Depreciation Reserve for AY1992	(6,070,780)
Taxes Deferred - ACRS (Adopted in GRC)	
Wtd. avg. Deferred Taxes - ACRS for AY1991	572,838
Wtd. avg. Deferred Taxes - ACRS for AY1992	(638,054)
Deferred ITC (Adopted in GRC)	
Wtd. Avg. Deferred ITC for TY1990	218,751
Wtd. Avg. Deferred ITC for AY1991	(208,873)
Wtd. avg. Depr Rate Base for AY1992	8,509,388
Wtd. avg. Depr. Rate Base in Attrition Year 1991	8,230,372
Wtd. avg. Depr. Rate Base in Attrition Year 1992	8,509,388
Wtd. avg. Depr. Rate Base in AY 1991 (Calif.)	8,000,167
Wtd. avg. Depr. Rate Base in AY 1992 (Calif.)	8,271,378

Long-term Debt

Return on Debt in AY 1991 (Adopted in AY1991)	9.32%
Debt capitalization in AY 1991 (Adopted in AY1991)	47.00%
Wtd. cost of Debt for Attrition Year 1991	4.38%
Return on Debt in AY 1992 (Adopted in AY1992)	9.32%
Debt capitalization in AY 1992 (Adopted in AY1992)	47.00%
Wtd. cost of Debt for Attrition Year 1992	4.38%
Increase in Debt cost in Attrition Year 1992	11,879
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.008650
Increase in Revenue Requirement	11,982

Preferred Stock

Return on Pref. Stock in AY 1991 (Adopted in AY1991)	8.79%
Pref.Stk. capitalization AY 1991 (Adopted in AY1991)	6.25%
Wtd. cost of Preferred Stock for Test Year 1991	0.55%
Return on Pref. Stock in AY 1992 (Adopted in AY1992)	8.79%
Pref.Stk. capitalization AY 1992 (Adopted in AY1992)	6.25%
Wtd. cost of Preferred Stock for Att. Year 1992	0.55%
Increase in Pref. Stock cost in Att. Year 1992	1,492
Net-to-Gross Multiplier (Adopted in GRC)	1.686792
Increase in Revenue Requirement	2,516

Common Equity

Return on Com. Eq. in AY 1991 (Adopted in AY1991)	12.90%
Com. Eq. capitalization AY 1991 (Adopted in AY1991)	46.75%
Wtd. cost of Common Equity for Test Year 1991	6.03%
Return on Com. Eq. in AY 1992 (Adopted in AY1992)	12.90%
Com. Eq. capitalization AY 1992 (Adopted in AY1992)	46.75%
Wtd. cost of Common Equity for Att. Year 1992	6.03%
Increase in Common Equity cost in Att. Year 1992	16,354
Net-to-Gross Multiplier (Adopted in GRC)	1.686792
Increase in Revenue Requirement	27,586

RATEBASE TRACKING

Wtd. avg. Depr.Rate Base in TY1990 (Adopted in GRC)	7,937,157
Wtd. avg. Depr.Rate Base in TY1990 (estimated at the time of filing for AY 1991)	7,937,157
Wtd. avg. Depr.RateBase in TY1990 (recorded)	7,937,157
Wtd. avg. Depr.RateBase in AY1991 (Adopted in GRC)	8,230,372
Wtd. avg. Depr.RateBase in AY1991 (estimated at the time of filing for AY 1991)	8,230,372
Wtd. avg. Depr.RateBase in AY1991 (use updated est.)	8,230,372
Wtd. avg. Depr.RateBase in AY1992 (Adopted in GRC)	8,509,388
Wtd. avg. Depr.RateBase in AY1992 (use updated est.)	8,509,388

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department - Total Company (Excl. Diablo Canyon)
REVENUE REQUIREMENTS FOR ATTRITION YEAR 1992
Thousands Of 1992$

ITEM	ATTRITION YEAR 1992
O & M EXPENSES :	
Labor Escalation	$31,855
Non-Labor Escalation	29,429
Total O&M Expenses	61,284
CAPITAL RELATED ITEMS :	
Book Depreciation Expenses	53,997
Ad Valorem Taxes	5,950
State Tax Depreciation	(2,635)
Federal Tax Depreciation	(12,053)
Debt cost	11,982
Preferred Stock cost	2,516
Common Equity cost	27,586
Total Capital Related Items	87,342
OTHER AUTHORIZED ITEMS :	
Humboldt Nuclear Decommissioning	(13,821)
Abandoned Project Amortization Adjustment	0
Non-recurring O&M Adjustment	0
SMUD Discounted Sales Adjustment	0
Total Other Authorized Items	(13,821)
ADD'L REVENUE REQUIREMENTS ---->	$134,806
Exclude % attributable to Large Light & Power (To be adopted in OIR 86-10-001)	0.00%
TOTAL ADD'L REVENUE REQUIREMENTS ---->	134,806

(END OF APPENDIX C)

APPENDIX D

	A	B	C	D	E	F	G	H	I	J	K	L
				PG&E D.C. REMOVAL				TOTAL A&G INCLUDING PG&E D.C. REMOVAL		ADOPTED BASE A&G	A&G REMOVAL FOR D.C.	ADOPTED A&G
	Acc. No.	Description	Comparison Exhibit	O&M	Direct	Peripherl	Total		A&G ADJUST.			
							(D+E+F)	(C+G)		(H-I)		(J-K)
1	920.0	A&G Salaries										
2		Labor	$110,506	$12,196	$0	$3,269	15,465	$125,971	$10,964	$115,007	$18,401	$96,606
3		Non-Labor	2,899	320	0	86	406	3,305	0	3,305	529	2,776
4		Other	0	0	0	0	0	0	0	0	0	0
5		Total	$113,405	$12,516	$0	$3,355	15,871	$129,276	$10,964	$118,312	$18,930	$99,382
6	921.0	Office Supplies and Exp.										
7		Labor	3,342	$66	$0	$209	275	$3,617	$0	$3,617	$579	$3,038
8		Non-Labor	30,181	601	0	1,883	2,484	32,665	0	32,665	5,226	27,439
9		Other	0	0	0	0	0	0	0	0	0	0
10		Total	$33,523	$667	$0	$2,092	2,759	$36,282	$0	$36,282	$5,805	$30,477
11	922.0	A&G Transfer Credit										
12		Labor	(20,834)	0	($1,435)	0	(1,435)	($23,715)	($2,006)	($21,708)	($3,473)	($18,235)
13		Non-Labor	(6,054)	0	(417)	0	(417)	(6,582)	0	(6,582)	(1,053)	(5,529)
14		Other	0	0	0	0	0	0	0	0	0	0
15		Total	($26,888)	$0	($1,852)	$0	(1,852)	($28,740)	($2,006)	($28,291)	($4,527)	($23,764)
16	923.0	Outside Serv. Employed										
17		Labor	95	$94	$0	$1	95	$190	$95	$95	$95	$0
18		Non-Labor	13,269	13,126	0	191	13,317	26,586	2,046	24,540	13,317	11,223
19		Other	0	0	0	0	0	0	0	0	0	0
20		Total	$13,364	$13,220	$0	$192	13,412	$26,776	$2,141	$24,635	$13,412	$11,223
21	924.0	Property Insurance										
22		Labor	0	$0	$0	$0	0	$0	$0	$0	$0	$0
23		Non-Labor	0	0	0	0	0	0	0	0	$0	0
24		Other	16,348	0	7,685	0	7,685	24,033	0	24,033	$7,685	16,348
25		Total	$16,348	$0	$7,685	$0	7,685	$24,033	$0	$24,033	$7,685	$16,348
26	925.0	Injuries and Damages										
27		Labor	0	$0	$0	$0	0	$0	$0	$0	$0	$0
28		Non-Labor	0	0	0	0	0	0	0	0	0	0
29		Other	37,843	0	667	1,209	1,876	39,719	2,067	37,652	1,876	35,776
30		Total	$37,843	$0	$667	$1,209	1,876	$39,719	$2,067	$37,652	$1,876	$35,776
31	926.0	Employee Pen.& Ben.										
32		Labor	2,331	$14	$262	$8	284	$2,615	$0	$2,615	$420	$2,195
33		Wage Related	82,411	506	9,264	276	10,046	92,457	11,442	81,015	13,011	68,004
34		Non-Labor	2,802	17	315	9	342	3,144	0	3,144	505	2,639
35		Other	74,460	457	8,370	250	9,077	83,537	3,902	79,634	12,789	66,845
36		Total	$162,004	$994	$18,211	$543	19,748	$181,752	$15,344	$166,408	$26,725	$139,683
37	928.0	Reg. Commission Exp.										
38		Labor	53	$0	$0	$5	5	$58	$0	$58	$8	$49
39		Non-Labor	(6)	0	0	(1)	(1)	(7)	0	(7)	($1)	(6)
40		Other	125	0	0	12	12	137	0	137	$20	117
41		Total	$172	$0	$0	$16	16	$188	$0	$188	$28	$160
42	930.0	Misc. General Exp.										
43		Labor	4,449	$0	$0	$0	0	$4,449	$0	$4,449	$0	$4,449
44		Non-Labor	15,684	0	0	0	0	15,684	0	15,684	0	15,684
45		Other	16,550	0	0	0	0	16,550	4,093	12,457	0	12,457
46		Total	$36,683	$0	$0	$0	0	$36,683	$4,093	$32,590	$0	$32,590
47	930.2	Other Misc. General Exp.										
48		Labor	884	$56	$4	$121	181	$1,065	$0	$1,065	$181	$884
49		Non-Labor	2,929	187	12	400	599	3,528	49	3,479	$599	2,880
50		Other	2,487	159	10	340	509	2,996	0	2,996	$509	2,487
51		Total	$6,300	$402	$26	$861	1,289	$7,589	$49	$7,540	$1,289	$6,251
52	931.0	Rents										
53		Labor	0	$0	$0	$0	0	$0	$0	$0	$0	$0
54		Non-Labor	16,221	0	0	1,722	1,722	17,943	0	17,943	2,871	15,072
55		Other	0	0	0	0	0	0	0	0	0	0
56		Total	$16,221	$0	$0	$1,722	1,722	$17,943	$0	$17,943	$2,871	$15,072
57	935.0	Maint. of General Plant										
58		Labor	2,322	$0	$0	$0	0	$2,322	$0	$2,322	$372	$1,950
59		Non-Labor	915	0	0	0	0	915	0	915	146	769
60		Other	0	0	0	0	0	0	0	0	0	0
		Total	$3,237	$0	$0	$0	0	$3,237	$0	$3,237	$518	$2,719
62		Total	$412,212	$27,799	$24,737	$9,990	$62,526	$474,738	$32,652	$440,529	$74,612	$365,917

(END OF APPENDIX D)

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
OPERATING REVENUES AT PRESENT RATES
Thousands Of 1990 Dollars
Test Year 1990

Description	Adopted
Residential	$1,121,549
Core Commercial	455,883
Non-Core Commercial	21,121
Industrial	268,312
Long-Term Transportation Contracts	13,143
Cogeneration	150,221
Power Plants - UEG	386,329
Resale	21,619
Inter-Utility	13,785
Enhanced Oil Recovery	33,801
Other Operating Revenues	9,149
Total Operating Revenues	$2,494,912
Less: Non-General Revenues	1,453,983
General Rate Case Revenues	$1,040,929

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
CALCULATION OF FRANCHISE FEES AND UNCOLLECTIBLES
Thousands Of 1990 Dollars
Test Year 1990

Description	Adopted
At Present Rates	
Revenues at Current Rates	$2,494,912
Less: Interdepartmental	397,516
Current Revenues from Customers	2,097,396
% of Revenues at Current Rates	84.07%
General Rate Case Revenues	$1,040,929
% of Revenues at Current Rates	84.07%
Revenues from Customers	$875,077
Uncollectibles Factor	0.00222
Uncollectibles	$1,943
Revenues From Customers	$875,077
Less: Uncollectibles	1,943
Net Revenues from Customers	$873,134
Franchise Requirement Factor	0.00916
Franchise Requirements	$7,994
Less: Sacramento Franchise Amort.	692
Total Franchise Requirements	$7,302

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
PRODUCTION EXPENSE
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Account No.	Description	Adopted
	Operation	
710.0	Supervision and Engineering	$1
717.0	Liquefied Petroleum Gas	0
733.0	Gas Mixing	5
735.0	Miscellaneous Production	379
807.2	Purchased Gas Meas. Stations	686
807.4	Purchased Gas Calculation	724
807.5	Other Purchased Gas	421
813.0	Other Gas Supply	329
	Total Operation	$2,545
	Maintenance	
740.0	Supervision and Engineering	10
741.0	Structures and Improvements	0
742.0	Production Equipment	1,254
411.7	Losses from Disp. of Plant	0
	Total Maintenance	$1,264
	TOTAL PRODUCTION (1987$)	$3,809
	Escalation Amounts, 1987 to 1990	
	Labor	272
	Non-Labor	196
	Other	0
	Total	$468
	TOTAL PRODUCTION (1990$)	$4,277

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
UNDERGROUND STORAGE EXPENSE
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Account No.	Description	Adopted
	Operation	
814.0	Supervision and Engineering	$68
815.0	Maps and Records	0
816.0	Wells	80
817.0	Lines	14
818.0	Compressor Station	791
819.0	Compressor Sta. Fuel and Power	2,854
820.0	Measuring & Regulating Station	239
821.0	Purification	3
824.0	Other	432
825.0	Storage Well Royalties	163
	Total Operation	$4,644
	Maintenance	
830.0	Supervision and Engineering	37
831.0	Structures and Improvements	2,559
832.0	Reservoirs and Wells	145
833.0	Lines	66
834.0	Compressor Station Equipment	89
835.0	Measuring & Reg Station Equip.	16
836.0	Purification Equipment	301
837.0	Other Equipment	86
	Total Maintenance	$3,299
	TOTAL UNDERGR. STORAGE (1987$)	$7,943
	Escalation Amounts, 1987 to 1990	
	Labor	130
	Non-Labor	1,007
	Other	0
	Total	$1,137
	TOTAL UNDERGR. STORAGE(1990$)	$9,080

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
LOCAL STORAGE EXPENSE
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Account No.	Description	Adopted
	Operation	
840.0	Supervision & Engineering	$16
841.0	Operation Labor and Expenses	33
842.1	Fuel	0
842.2	Power	150
	Total Operation	$199
	Maintenance	
843.1	Supervision and Engineering	33
843.2	Structures and Improvements	0
843.4	Gas Holders	133
843.9	Other Equipment	1
843.9	Compressor Equipment	12
	Total Maintenance	$179
	TOTAL LOCAL STORAGE (1987$)	$378
	Escalation Amounts, 1987 to 1990	
	Labor	13
	Non-Labor	40
	Other	0
	Total	$53
	TOTAL LOCAL STORAGE (1990$)	$431

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
TRANSMISSION EXPENSE
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Account No.	Description	Adopted
	Operation	
850.0	Supervision and Engineering	$3,628
851.0	System Con. & Load Dispatch	3,629
853.0	Compressor Station	4,152
855.0	Other Fuel & Power for Compr.	294
856.0	Mains Expense	1,694
856.0	Removal of Condensate	(100)
857.0	Mearsuring & Reg. Station Exp.	2,752
858.0	Trans & Comp of Gas by Others	0
859.0	Transmission Maps and Records	247
859.0	Other Expenses	3,140
859.0	Joint Expenses	1,468
860.0	Rents	88
	Total Operation	$20,992
	Maintenance	
861.00	Supervision and Engineering	1,299
862.00	Structures and Improvements	95
863.00	Mains	2,229
864.00	Compressor Station Equipment	6,107
865.00	Measuring & Reg Station Equip.	1,145
867.00	Other Equipment	122
	Total Maintenance	$10,997
	TOTAL TRANSMISSION (1987$)	$31,989
	Escalation Amounts, 1987 to 1990	
	Labor	2,034
	Non-Labor	2,001
	Other	0
	Total	$4,036
	TOTAL TRANSMISSION (1990$)	$36,024

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
DISTRIBUTION EXPENSE
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Account No.	Description	Adopted
	Operation	
870.0	Supervision and Engineering	$9,853
871.0	Load Dispatching	629
874.0	Mains and Services	2,130
875.0	Meas & Reg Station - General	580
876.0	Meas & Reg Station - Industrial	805
878.0	Rem & Res Meters & Regulators	19,383
878.0	Miscellaneous Meter Expenses	745
879.0	Cust. Instal. Exp. - General	15,138
880.0	Maps and Records	3,644
880.0	Other Expenses	21,331
881.0	Rents	156
	Total Operation	$74,394
	Maintenance	
885.00	Supervision and Engineering	4,160
886.00	Structures and Improvements	4
887.00	Mains - Leak Clamps	2,704
887.00	Mains - Other	11,779
888.00	Compressor Station Equipment	0
889.00	Meas & Reg Station - General	1,653
890.00	Meas & Reg Station - Industrial	942
892.00	Services	9,020
893.00	Meters	3,608
893.00	House Regulators	972
894.00	Other Equipment	339
	Total Maintenance	$35,181
	TOTAL DISTRIBUTION (1987$)	$109,575
	Escalation Amounts, 1987 to 1990	
	Labor	7,561
	Non-Labor	5,989
	Other	0
	Total	$13,550
	TOTAL DISTRIBUTION (1990$)	$123,125

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
CUSTOMER ACCOUNTS EXPENSE
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Account No.	Description	Adopted
901.0	Supervision	$3,344
902.0	Meter Reading Expenses	15,542
903.0	Customer Contracts and Orders	19,393
903.0	Customer Billing & Accounting	7,609
903.0	Mailing Customer Bills	$5,893
903.0	Collecting Expenses	14,095
904.0	Uncollectible Accounts	1,943
905.0	Misc. Customer Accounts Exp.	7,403
905.0	Rents	48
	TOTAL CUSTOMER ACCTS. (1987$)	$75,270
	Total (Less Uncollectibles)	$73,327
	Escalation Amounts, 1987 to 1990	
	Labor	5,869
	Non-Labor	2,009
	Other	0
	Total	$7,877
	TOTAL CUSTOMER ACCTS. (1990$)	$83,147
	Total (Less Uncollectibles)	$81,204

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
DEMAND-SIDE MANAGEMENT EXPENSES
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Account No.	Description	Adopted
	Residential & Non-Residential Conservation, Service Planning, and Measurement and Evaluation	
907.0	Supervision	$1,093
908.0	Customer Assistance Expense	30,186
909.0	Informational & Instructional Exp	916
910.0	Miscellaneous	1,488
	Subtotal	33,683
	Load Retention & Load Bldg. Exp.	
911.0	Supervision	$253
912.0	Demonstrating & Selling	1,012
913.0	Advertising	0
916.0	Miscellaneous	641
916.0	Rents	0
	Subtotal	1,906
	TOTAL DEMAND-SIDE MGMT (1987$)	$35,589
	Escalation Amounts, 1987 to 1990	
	Labor	1,047
	Non-Labor	3,674
	Other	0
	Total	$4,720
	TOTAL DEMAND-SIDE MGMT (1990$)	$40,309

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
ADMINISTRATIVE & GENERAL EXPENSES
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Account No.	Description	Adopted
	Operation	
920.0	Administrative & Gen. Salaries	$49,489
921.0	Office Supplies and Expenses	17,583
922.0	Admin. & Gen. Transfer Credit	(12,274)
923.0	Outside Services Employed	4,741
924.0	Property Insurance	1,605
925.0	Injuries and Damages	11,036
926.0	Employee Pensions and Benefits	63,394
927.0	Franchise Requirements	7,302
928.0	Regulatory Commission Expenses	62
930.0	Regulatory Commission Expenses	7,042
930.0	Regulatory Commission Expenses	3,181
930.2	Other Misc. General Expenses	0
931.0	Rents	8,061
	Total Operation	$161,222
	Maintenance	
932.0	Maintenance of General Plant	1,609
	Total Maintenance	1,609
	TOTAL ADMIN. & GEN. (1987$)	$162,831
	Total (Less Franchise Req.)	$155,528
	Escalation Amounts, 1987 to 1990	
	Labor	4,789
	Wage-related	3,272
	Non-Labor	5,105
	Other	0
	Total	$13,166
	TOTAL ADMIN. & GEN. (1990$)	$175,997
	Total (Less Franchise Req.)	$168,694

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
EXPENSE SUMMARY
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Description	Adopted
TOTAL NON-ESCALATED (1987$)	
Production	$3,809
Underground Storage	7,943
Local Storage	378
Transmission	31,989
Distribution	109,575
Customer Accounts	75,270
Demand-Side Management	35,589
Administrative and General	162,831
Other Adjustments	(6,520)
Total Non-Escalated (1987$)	$420,863
TOTAL ESCALATED (1990$)	
Production	4,277
Underground Storage	9,080
Local Storage	431
Transmission	36,024
Distribution	123,125
Customer Accounts	83,147
Demand-Side Management	40,309
Administrative and General	175,997
Other Adjustments	(7,221)
Total Escalated (1990$)	$465,169
TOTAL ESCALATION (1987$ to 1990$)	
Production	468
Underground Storage	1,137
Local Storage	53
Transmission	4,036
Distribution	13,550
Custoer Accounts	7,877
Demand-Side Management	4,720
Administrative and General	13,166
Other Adjustments	(701)
Total Escalation	$44,306

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
LABOR SUMMARY
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Description	Adopted
LABOR NON-[illegible]	

CORRECTION

THIS DOCUMENT HAS

BEEN REPHOTOGRAPHED

TO ASSURE

LEGIBILITY

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
LABOR SUMMARY
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Description	Adopted
LABOR NON-ESCALATED (1987$)	
Production	$2,528
Underground Storage	1,210
Local Storage	118
Transmission	18,927
Distribution	70,345
Customer Accounts	54,600
Demand-Side Management	9,737
Administrative and General	44,553
Other Adjustments	(6,520)
Total Non-Escalated Labor	$195,498
Wage-related A&G	30,438
Total	225,936
Labor Escalation Factor	1.10749
LABOR ESCALATED (1990$)	
Production	2,800
Underground Storage	1,340
Local Storage	131
Transmission	20,961
Distribution	77,906
Customer Accounts	60,469
Demand-Side Management	10,784
Administrative and General	49,341
Other Adjustments	(7,221)
Total Non-Escalated Labor	$216,512
Wage-related A&G	33,710
Total	$250,221
LABOR ESCALATION (1987$ to 1990$)	
Steam Production	272
Nuclear Production	130
Hydraulic Production	13
Transmission	2,034
Distribution	7,561
Customer Accounts	5,869
Customer Service & Informational	1,047
Administrative and General	4,789
Other Adjustments	(701)
Total Labor Escalation	$21,014
Wage-related A&G	3,272
Total	$24,285

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
NON-LABOR SUMMARY
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Description	dopted
NON-LABOR NON-ESCALATED (1987$)	
Production	$1,281
Underground Storage	6,570
Local Storage	260
Transmission	13,062
Distribution	39,089
Customer Accounts	13,110
Demand-Side Management	23,978
Administrative and General	33,321
Other Adjustments	0
Total Non-Escalated Non-Labor	$130,671
Non-Labor Escalation Factor	1.15321
NON-LABOR ESCALATED (1990$)	
Production	1,477
Underground Storage	7,577
Local Storage	300
Transmission	15,063
Distribution	45,078
Customer Accounts	15,119
Demand-Side Management	27,652
Administrative and General	38,426
Other Adjustments	0
Total Escalated Non-Labor	$150,691
NON-LABOR ESCALATION (1987$ to 1990$)	
Production	196
Underground Storage	1,007
Local Storage	40
Transmission	2,001
Distribution	5,989
Customer Accounts	2,009
Demand-Side Management	3,674
Administrative and General	5,105
Other Adjustments	0
Total Non-Labor Escalation	$20,020
Other Taxes	0
Total Non-Labor Escalation	$20,020

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
OTHER SUMMARY
(Thousands Of 1987 Dollars Unless Otherwise Indicated)
Test Year 1990

Description	Adopted
OTHER NON-ESCALATED (1987$)	
Production	$0
Underground Storage	163
Local Sorage	0
Transmission	0
Distribution	141
Customer Accounts	7,560
Demand-Side Management	1,874
Administrative and General	54,519
Other Adjustments	0
Total Non-Escalated Other	$64,257
Other Escalation Factor	1.0000
OTHER ESCALATED (1990$)	
Production	0
Underground Storage	163
Local Storage	0
Transmission	0
Distribution	141
Customer Accounts	7,560
Demand-Side Management	1,874
Administrative and General	54,519
Other Adjustments	0
Total Escalated Other	$64,257
OTHER ESCALATION (1987$ to 1990$)	
Production	0
Underground Storage	0
Local Storage	0
Transmission	0
Distribution	0
Customer Accounts	0
Demand-Side Management	0
Administrative and General	0
Other Adjustments	0
Total Other Escalation	$0

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
TAXES OTHER THAN ON INCOME
Thousands Of 1990 Dollars
Test Year 1990

Description	Adopted
Ad Valorem Taxes	
Ca., Ariz., N.M., Nev.	$23,492
Total Ad Valorem Taxes	23,492
Payroll Taxes	
Federal Insurance Contrib. Act	16,585
Federal Unemployment Insurance	302
State Unemployment Insurance	414
San Francisco Payroll Tax	1,150
Total Payroll Taxes	18,450
Miscellaneous Taxes	
Business and Other	639
Total Miscellaneous Taxes	639
Total Taxes OTOI	$42,581

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
INCOME TAX ADJUSTMENTS
Thousands Of 1990 Dollars
Test Year 1990

Description	Adopted
California Income Tax Adjustments	
Tax Depreciation	$142,338
Interest Charges	93,625
Fiscal/Calendar Adjustment	1,322
Operating Expense Adjustments	(315)
Capitalized Interest Adjustment	(7,157)
Capitalized Inventory Adjustment	(14,025)
Vacation Accrual Reduction	(1,590)
Ad Valorem Taxes Capitalized	58
Capitalized Pension and Benefits	1,502
Removal Cost	5,180
Repair Allowance	580
	$221,518
Federal Income Tax Adjustments	
Tax Depreciation	124,658
Fiscal/Calendar Adjustment	1,322
Operating Expense Adjustments	(315)
Interest Charges	93,625
Capitalized Interest Adjustment	(7,157)
Capitalized Inventory Adjustment	(14,025)
Vacation Accrual Reduction	(1,590)
Ad Valorem Taxes Capitalized	58
Capitalized Pension and Benefits	1,502
Removal Cost	5,180
Repair Allowance	160
Preferred Dividend Credit	485
	$203,903

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
TAXES ON INCOME - ADOPTED RATES
Thousands Of 1990 Dollars
Test Year 1990

Description	Adopted
California Corporation Franchise Tax	
Operating Revenues	$1,040,929
Operating Expenses	465,169
Taxes Other Than On Income	42,581
Income Tax Adjustments	221,518
Superfund tax	360
California Taxable Income	$311,300
CCFT Tax Rate	9.30%
CCFT	$28,951
CCFT CREDITS	
Defense Facilities Credit	(2)
Deferred Taxes - Other	(3)
Deferred Taxes - Interest	(666)
Deferred Taxes - Vacation	(148)
TOTAL CCFT	$28,132
Federal Income Tax	
Operating Revenues	$1,040,929
Operating Expenses	465,169
Taxes Other Than On Income	42,581
CCFT	28,951
Income Tax Adjustments	203,903
Superfund tax	360
Federal Taxable Income	$299,965
FIT Tax Rate	34.00%
FIT	$101,988
FIT CREDITS	
Flowback of Excess Def'rd Taxes	(466)
Defense Facilities Credit	(16)
Deferred Taxes - Other	45
Deferred Taxes - Interest	(2,207)
Deferred Taxes - Vacation	(490)
TOTAL FIT	98,854

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
DEPRECIATION EXPENSE
Thousands Of 1990 Dollars
Test Year 1990

Description	Adopted
Production	61
Underground Storage	6,482
Local Storage	2,290
Transmission	33,679
Distribution	114,414
General Plant	1,031
Common Plant	29,705
6/7 Interest in Stanpac	334
Subtotal	$187,996

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
DEPRECIATION RESERVE
Thousands Of 1990 Dollars
Test Year 1990

Description	Adopted
Depreciation Reserve - BOY	
Production	$734
Underground Storage	60,249
Local Storage	4,428
Transmission	392,554
Dstribution	989,340
General Plant	11,309
Common Plant	190,242
6/7 Interest in Stanpac	3,785
Depreciation Reserve - BOY	$1,652,641
Other Adjustments (excl. Depr. expense)	
Production	$0
Underground Storage	546
Local Storage	796
Transmission	2,107
Distribution	26,796
General Plant	19
Common Plant	(5,682)
6/7 Interest in Stanpac	734
Other Adjustments (excl. depr.)	30,264
Depreciation Reserve - EOY	
Production	$795
Underground Storage	$66,185
Local Storage	$5922
Transmission	$424,126
Distribution	$1,076,958
General Plant	$12,321
Common Plant	$225,629
6/7 Interest in Stanpac	$3,385
Depreciation Reserve - EOY	1,815,321
Depreciation Reserve - Wtd. avg.	$1,733,981

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
GAS PLANT IN SERVICE - EOY
Thousands Of 1990 Dollars
Test Year 1990

Description	Adopted
Plant in Service - BOY	
Intangibles	659
Production	1,419
Underground Storage	199,865
Local Storage	20,444
Transmission Plant	869,199
Distribution Plant	2,184,119
General Plant	26,605
Common Plant	517,875
6/7 Interest in Stanpac	17,270
Total Plant in Service : BOY	3,837,455
Plant in Service - Net Additions	
Intangibles	0
Production	185
Underground Storage	11,575
Lcal Storage	(681)
Transmission Plant	123,135
Distribution Plant	141,590
General Plant	247
Common Plant	69,472
6/7 Interest in Stanpac	6,335
Total Net Additions	351,858
Plant in Service - EOY	
Intangibles	659
Production	1,604
Underground Storage	211,440
Local Storage	19,763
Transmission Plant	992,334
Distribution Plant	2,325,709
General Plant	26,852
Common Plant	587,347
6/7 Interest in Stanpac	23,605
Total Plant in Service : EOY	4,189,313

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
GAS PLANT IN SERVICE - WTD. AVG.
Thousands Of 1990 Dollars
Test Year 1990

Description	Adopted
Plant in Service - BOY	
Intangibles	$659
Production	1,419
Underground Storage	199,865
Local Storage	20,444
Transmission Plant	869,199
Distribution Plant	2,184,119
General Plant	26,605
Common Plant	517,875
6/7 Interest in Stanpac	17,270
Total Plant in Service : BOY	3,837,455
Plant in Service - Weighted Average Net Additions	
Intangibles	$0
Production	92
Underground Storage	4,434
Local Storage	(337)
Transmission Plant	53,778
Distribution Plant	69,234
General Plant	122
Common Plant	26,850
6/7 Interest in Stanpac	3,145
Total Wtd. Avg. Net Additions	157,318
Total Plant in Service - Weighted Average	
Intangibles	$659
Production	1,511
Underground Storage	204,299
Local Storage	20,107
Transmission Plant	922,977
Distribution Plant	2,253,353
General Plant	26,727
Common Plant	544,725
6/7 Interest in Stanpac	20,415
Total Plant in Service : Wtd. Avg.	3,994,773

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
WEIGHTED AVERAGE DEPRECIATED RATE BASE
Thousands Of 1990 Dollars
Test Year 1990

Description	
FIXED CAPITAL @ BEGINNING OF YEAR	
Plant in Service - BOY	$3,837,455
Common Plant Held for Future Use	11
Total Fixed Capital - BOY	$3,837,466
WTD. AVG. NET ADDITIONS	
Plant in Service - Wtd. Avg. Additions	157,318
Common Plant Held for Future Use	0
Total Wtd. Avg. Additions	$157,318
Tot. Wtd. Avg. Fixed Capital	$3,994,784
TAX REFORM ACT ADJUSTMENTS	
Deferred Capitalized Interest	5,225
Deferred Vacation	11,535
Deferred CIAC Tax Effects	6,896
Total Tax Reform Act Adjustments	$23,656
ADJUSTMENTS	
Cust. Adv. for Construction	(48,231)
Total Adjustments	($48,231)
WORKING CAPITAL	
Gas Line Pack	8,639
Materials & Supplies	23,057
Working Cash	48,797
Total Working Capital	$80,493
Tot. Before Ded. for Reserves	$4,050,702
DEDUCTIONS FOR RESERVES	
Wtd.Avg.Depreciation Reserve	1,733,981
Taxes Def. - Defense	18
Taxes Def. - ACRS/MACRS	118,497
Taxes Def. - Other	(2,550)
Deferred ITC	63,196
Total Ded. for Reserves	$1,913,142
Weighted Average Depreciated Rate Base	$2,137,560

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
DETERMINATION OF AVERAGE AMOUNTS OF WORKING
CASH CAPITAL SUPPLIED BY INVESTORS
Thousands Of 1990 Dollars
Test Year 1990

Description	Adopted
Operational Cash Requirements	
Cash	37,440
Special Deposits and Working Funds	4,058
Other Receivables	29,219
Prepayments	10,721
Deferred Debits, Company-Wide	4,166
Total	$85,604
Less: Amounts Not Supplied By Investors	
Accrued Vacation & Empl. Witholdings	88,522
Credit recd. for capitlized supplies	22,033
Total	$110,555
Subtotal, Total Company	($24,951)
Gas Department Allocation Percentage	33.16%
Gas Department Allocation	(8,274)
Franchise Fee Amortization	(1,643)
Deferred Debits - Gas Department	58
Total Operational Cash Requirement	($9,859)
Plus: Average Amount Required	
Avg. Amt. Req. as a Result of Paying Expenses in Advance of Collecting Revenues	58,656
Total	$58,656
Average Net Amount of Working Cash Capital Supplied by Investors	$48,797

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
DEVELOPMENT OF AVERAGE LAG IN PAYMENT OF EXPENSES
Thousands Of 1990 Dollars
Test Year 1990

Description	Expense	Average Lag Days	Product
	(A)	(B)	(C=AxB)
Natural Gas Purchase	1,130,835	37.08	41931362
Federal Income Tax	110,879	98.96	10972594
Ad Val.Tax	23,492	43.74	1027519
Payroll	242,716	14.20	3446570
Franchise Requiremen	16,336	255.41	4172492
Goods and Services	102,435	32.94	3374212
Pensions	22,622	-3.92	-88677
S.F. Payroll Expense	1,150	137.37	158029
FICA Tax	16,585	6.64	110123
Federal Unempl. Tax	302	73.93	22304
State Unempl. Tax	414	75.66	31288
Group Life Insurance	3,175	-18.84	-59824
State Corp. Tax	31,548	80.33	2534273
Depreciation	187,996	0.0	0
Materials From Store	40,034	0.00	0
Insurance and Casual	12,641	18.84	238156
Income Taxes Deferre	11,628	0.00	0
Abandoned Project Am	6,802	0.00	0
Savings Fund Plan	5,371	0.00	0
Health Vision Dental	27,569	8.21	226343
Adj. to ERTA Tax Bas	(15,581)	98.96	-1541882
TOTAL	1978949		66554882

Exp. Lag Days	33.63	= (C)/(A)
Revenue Lag Days	44.45	
Adj. to Rate Bas	58,656	
Rate Base Factor	2,078,904	
New Rate Base	$2,137,560	

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
SUMMARY OF EARNINGS AT ADOPTED PRESENT RATE
REVENUES AND EXPENSES
(Thousands Of 1990 Dollars Unless Otherwise Indicated)
Test Year 1990

Description	Adopted
Operating Revenues	
Revenues	$1,040,929
Total Operating Revenues	$1,040,929
Operating Expenses	
Production	12,130
Transmission	31,989
Distribution	109,575
Customer Accounts	73,327
Uncollectibles	1,943
Customer Service & Informational	35,589
Administrative & General	155,528
Franchise Requirements	7,302
Other Adjustments	(6,520)
Subtotal (1987 Dollars)	$420,863
Labor Escalation Amoun	24,285
Non-Labor Escalation Amount	20,020
Subtotal (1990 Dollars)	$465,169
Natural Gas Used by the Gas Department	(141)
Project Amortization	6,802
Depreciation	187,996
Taxes Other Than On Income	42,581
Superfund tax	360
CA Corporation Franchise Tax	28,132
Federal Income Tax	98,854
Total Operating Expenses	$829,753
Net Operating Income	$211,176
Rate Base	2,137,560
Rate of Return	9.88%

Auth. Rate of Return :	10.96%
Net-to-Gross multiplier :	1.68845
Authorized incr. in Revenues :	$39,005

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
ADOPTED SUMMARY OF EARNINGS
REVENUES AND EXPENSES
(Thousands Of 1990 Dollars Unless Otherwise Indicated)

Description	Adopted
Operating Revenues	
Adopted Present Rate Revenues	$1,040,929
Authorized incr. in Revenues	39,005
Total Operating Revenues	$1,079,934
Operating Expenses	
Production	13,787
Transmission	36,024
Distribution	123,125
Customer Accounts	81,204
Uncollectibles	2,015
Cust. Serv. & Inform.	40,309
Administrative & Gen.	168,694
Franchise Requirements	7,602
Other Adjustments	(7,221)
Subtotal (1990 Dollars)	$465,542
Natural Gas Used by the Gas Department	(141)
Projec Amortization	6,802
Depreciation	187,996
Taxes Other Than On Income	42,581
Superfund tax	403
CA Corporation Franchise Tax	31,721
Federal Income Tax	111,033
Total Operating Expenses	$845,936
Net Operating Income	$233,998
Rate Base	2,137,560
Rate of Return	10.95%

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
DEVELOPMENT OF THE NET-TO-GROSS MULTIPLIER
Test Year 1990

Description	(A)	(B)	(C=A*B)
Gross Operating Revenues			1.000000
Less: Uncoll.	0.002220	0.840669	0.001866
			0.998134
Less: Franchise	0.009156	0.838803	0.007680
			0.990454
Less: Super Fund	0.001200	0.897365	0.001077
			0.989377
Less: S.I.T.	0.093000	0.989377	0.092012
			0.897365
Less: F.I.T.	0.340000	0.897365	0.305104
Net Operating Revenues			0.592261

Uncollectibles & Franchise Fee Factor	1.009638
Superfund, State & Federal Tax Factor	1.672327
Net-To-Gross Multiplier	1.688446

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
ESCALATION FACTORS
COST OF CAPITAL
Test Year 1990

Description		Adopted
LABOR ------------>	1988	2.750%
ESCALATION FACTORS	1989	2.750%
	1990	4.900%
	1991	4.200%
	1992	4.800%
NON-LABOR -------->	1988	5.170%
ESCALATION FACTORS	1989	4.600%
	1990	4.830%
	1991	5.270%
	1992	5.460%
OTHER ------------>	ALL YEARS	0.000%

COMPOSITE ESCALATION FACTORS

LABOR	1988 TO 1991	10.749%
NON-LABOR	1987 TO 1990	15.321%
OTHER	1987 TO 1990	0.000%

	COST	CAPITALIZATION	WTD. COST
Debt	9.32%	47.00%	4.38%
Pref. Stock	8.79%	6.25%	0.55%
Common equity	12.90%	46.75%	6.03%
Auth. Return on Rate Base :			10.96%

(END OF APPENDIX E)

ATTRITION YEAR 1991

	Expenses for AY1991 in 000's of 1990$	Expenses for AY1991 in 000's of 1990$ (Calif.)	Transfer of Other Expenses to Labor/ Non-Labor	Expenses for AY1991 in 000's of 1990$ for Attrition purposes
	A D O P T E D	I N	G R C	
Production (Juris. Alloc. Factr =			1.0000	
Labor	4,270	4,270	0	4,270
Non Labor	9,354	9,354	0	9,354
Other	163	163	0	163
	13,787	13,787	0	13,787
Transmission (Juris. Alloc. Factor =			1.0000	
Labor	20,961	20,961	0	20,961
Non Labor	15,063	15,063	0	15,063
Other	0	0	0	0
	36,024	36,024	0	36,024
Distribution (Juris. Alloc. Factor =			1.0000	
Labor	77,906	77,906	0	77,906
Non Labor	45,078	45,078	0	45,078
Other	141	141	0	141
	123,125	123,125	0	123,125
Customer Accounts (Juris. Alloc. Factor			1.0000	
Labor	60,469	60,469	0	60,469
Non Labor	15,119	15,119	0	15,119
Other	7,632	7,632	0	7,632
	83,220	83,220	0	83,220
Demand-Side Mgmt. (Juris. Alloc. Factor			1.0000)	
Labor	10,784	10,784	0	10,784
Non Labor	27,652	27,652	0	27,652
Other	1,874	1,874	0	1,874
	40,309	40,309	0	40,309
Admin. & Gen. (Juris. Alloc. Factor =			1.0000	
Labor	83,051	83,051	30,728	113,779
Non Labor	38,426	38,426	16,489	54,915
Other	54,819	54,819	(47,217)	7,602
	176,296	176,296	0	176,296

	Expenses for AY1991 in 000's of 1990$	Expenses for AY1991 in 000's of 1990$ (Calif.)	Transfer of Other Expenses to Labor/ Non-Labor	Expenses for AY1991 in 000's of 1990$ for Attrition purposes
	ADOPTED IN GRC			
Other Adjustments (Juris. Alloc. Factor			1.0000	
Labor	(7,221)	(7,221)	0	(7,221)
Non Labor	0	0	0	0
Other	0	0	0	0
	(7,221)	(7,221)	0	(7,221)
TOTAL O&M EXPENSES				
Labor	250,221	250,221	30,728	280,949
Non Labor	150,691	150,691	16,489	167,180
Other	64,629	64,629	(47,217)	17,412
	465,542	465,542	0	465,542

Labor Base for AY 1991 in 1990$ (Adopted in GRC)	$280,949
1990 Labor Escalation (estimated in GRC)	4.90%
1989 Labor Escalation (estimated in GRC)	2.75%
1988 Labor Escalation (estimated in GRC)	2.75%
1988 Labor Escalation (use recorded)	2.75%
1989 Labor Escalation (use recorded)	2.75%
1990 Labor Escalation (use updated estimate)	4.90%
1991 Labor Escalation (use updated estimate of CPI-Wage Earners)	4.20%
Labor Base for AY 1991 in 1990$	292,749
Labor Escalation for AY 1991 in 1991$	11,800
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009638
Increase in Revenue Requirement	11,914
Non-Labor Base for AY 1991 in 1990$ (Adopted in GRC)	167,180
1990 Non-Labor Escalation (estimated in GRC)	4.83%
1989 Non-Labor Escalation (estimated in GRC)	4.60%
1988 Non-Labor Escalation (estimated in GRC)	5.17%
1988 Non-Labor Escalation (recorded)	5.17%
1989 Non-Labor Escalation (recorded)	4.60%
1990 Non-Labor Escalation (use updated estimate)	4.83%
1991 Non-Labor Escalation (use updated estimate)	5.27%
Non-Labor Base for AY 1991 in 1991$	175,990

Non-Labor Escalation for AY 1991 in 1991$	8,810
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009638
Increase in Revenue Requirement	8,895

Depreciation Exp. (Juris. Alloc. Factor 1.0000)

System avg. Depreciation Rate (Adopted in GRC)	4.7061%
Increase in Wtd. Avg. Plant in Service for AY1991 (Adopted in GRC)	337,529
Increase in Depreciation expense	15,884
Increase in Depreciation expense (Calif.)	15,884
Net-to-Gross Multiplier (Adopted in GRC)	1.688446
Increase in Revenue Requirement	26,820

Ad Valorem Taxes (Juris. Alloc. Factor 1.0000)

System avg. Ad Valorem Tax Rate (Adopted in GRC)	0.5607%
Increase in AY1991 EOY Plant in Service from TY1990 EOY Plant in Service (Adopted in GRC)	319,810
Increase in Ad Valorem Taxes	1,793
Increase in Ad Valorem Taxes (Calif.)	1,793
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009638
Increase in Revenue Requirement	1,811

State Tax Depr. (Juris. Alloc. Factor = 1.0000)

State Tax Depr. Rate (Adopted in GRC)		3.3977%
Increase in AY1991 EOY Plant in Service from TY1990 EOY Plant in Service (Adopted in GRC)		319,810
Increase in State Tax Depreciation		10,866
Increase in State Tax Depreciation (Calif.)		10,866
Increase in CCFT (Tax Rate =	9.3000%	(1,011)
Increase in FIT (Tax Rate =	34.0000%	344
Increase in State & Federal Taxes		(667)
Net-to-Gross Multiplier (Adopted in GRC)		1.688446
Increase in Revenue Requirement		(1,126)

Federal Tax Depr. (Juris. Alloc. Factor 1.0000)		
Federal Tax Depr. Rate (Adopted in GRC)		2.9756%
Increase in AY1991 EOY Plant in Service from TY1990 EOY Plant in Service (Adopted in GRC)		319,810
Increase in Federal Tax Depreciation		9,516
Increase in Federal Tax Depreciation (Calif.)		9,516
Increase in Federal Taxes (Tax Rate	34.0000%	(3,236)
Net-to-Gross Multiplier (Adopted in GRC)		1.688446
Increase in Revenue Requirement		(5,463)

Rate Base (Juris. Alloc. Factor = 1.0000)	
Wtd. avg. Depr Rate Base for TY1990 (Adopted in GRC)	2,137,560
Plant in Service (Adopted in GRC)	
Wtd. avg. Additions for TY990	(157,318)
Net Additions for TY1990	351,858
Wtd. avg. Additions for AY1991	142,989
Plant Held for Future Use (Adopted in GRC)	
Wtd. avg. Additions for TY1990	(11)
Net Additions for TY1990	17
Wtd. avg. Additions for AY1991	0
Deferred ITC (Adopted in GRC)	
Wtd. Avg. Deferred ITC for TY1990	63,196
Wtd. Avg. Deferred ITC for AY1991	(60,185)
Depreciation Reserve (Adopted in GRC)	
Wtd. avg. Depreciation Reserve for TY1990	1,733,981
Wtd. avg. Depreciation Reserve for AY1991	(1,900,851)
Taxes Deferred - ACRS (Adopted in GRC)	
Wtd. avg. Deferred Taxes - ACRS for TY1990	118,497
Wtd. avg. Deferred Taxes - ACRS for AY1991	(139,043)
Wtd. avg. Depr Rate Base for AY1991	2,290,691
Wtd. avg. Depr. Rate Base in TY1990 (Adopted in GRC)	2,137,560
Wtd. avg. Depr. Rate Base in AY1991 (Adopted in GRC)	2,290,691
Wtd. avg. Depr. Rate Base in TY 1990 (Calif.)	2,137,560
Wtd. avg. Depr. Rate Base in AY 1991 (Calif.)	2,290,691

Long-term Debt

Return on Debt in TY 1990 (Adopted in GRC)	9.32%
Debt capitalization in TY 1990 (Adopted in GRC)	47.00%
Wtd. cost of Debt for Test Year 1990	4.38%
Return on Debt in AY 1991 (Adopted in AY1991)	9.32%
Debt capitalization in AY 1991 (Adopted in AY1991)	47.00%
Wtd. cost of Debt for Attrition Year 1991	4.38%
Increase in Debt cost in Attrition Year 1991	6,707
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009638
Increase in Revenue Requirement	6,772

Preferred Stock

Return on Pref. Stock in TY 1990 (Adopted in GRC)	8.79%
Pref.Stk. capitalization in TY1990 (Adopted in GRC)	6.25%
Wtd. cost of Preferred Stock for Test Year 1990	0.55%
Return on Pref. Stock in AY1991 (Adopted in AY1991)	8.79%
Pref.Stk. capitalization AY1991 (Adopted in AY1991)	6.25%
Wtd. cost of Preferred Stock for Att. Year 1991	0.55%
Increase in Pref. Stock cost in Att. Year 1991	842
Net-to-Gross Multiplier (Adopted in GRC)	1.688446
Increase in Revenue Requirement	1,422

Common Equity

Return on Common Equity in TY 1990 (Adopted in GRC)	12.90%
Com. Equity capitalization TY 1990 (Adopted in GRC)	46.75%
Wtd. cost of Common Equity for Test Year 1990	6.03%
Return on Common Equity AY 1991 (Adopted in AY1991)	12.90%
Com. Eq. capitalization AY 1991 (Adoptd in AY1991)	46.75%
Wtd. cost of Common Equity for Att. Year 1991	6.03%
Increase in Common Equity cost in Att. Year 1991	9,234
Net-to-Gross Multiplier (Adopted in GRC)	1.688446
Increase in Revenue Requirement	15,591

RATEBASE TRACKING

Wtd. avg. Depr.RateBase in TY1990 (Adopted in GRC)	2,137,560
Wtd. avg. Depr.RateBase in TY1990 (use updated est.)	2,137,560
Wtd. avg. Depr.RateBase in AY1991 (Adopted in GRC)	2,290,691
Wtd. avg. Depr.RateBase in AY1991 (use updated est.)	2,290,691

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
REVENUE REQUIREMENTS FOR ATTRITION YEAR 1991
Thousands Of 1991$

ITEM	ATTRITION YEAR 1991
O & M EXPENSES :	
Labor Escalation	$11,914
Non-Labor Escalation	8,895
Total O&M Expenses	$20,809
CAPITAL RELATED ITEMS :	
Book Depreciation Expenses	$26,820
Ad Valorem Taxes	1,811
State Tax Depreciation	(1,126)
Federal Tax Depreciation	(5,463)
Debt cost	6,772
Preferred Stock cost	1,422
Common Equity cost	15,591
Total Capital Related Items	$45,826
OTHER AUTHORIZED ITEMS :	
Abandoned Project Amortization Adjustment	($6,802)
Non-recurring O&M Adjustment	0
Total Other Authorized Items	($6,802)
ADD'L REVENUE REQUIREMENTS ---->	$59,833
Exclude % attributable to Large Light & Power (To be adopted in OIR 86-10-001)	0.00%
TOTAL ADD'L REVENUE REQUIREMENTS ---->	$59,833

ATTRITION YEAR 1992

Labor Base

Total Labor Base for AY 1992 in 1991$	292,749
1991 Labor Escalation (estimated in GRC)	4.20%
1990 Labor Escalation (estimated in AY1989)	4.90%
1990 Labor Escalation (use recorded)	4.90%
1991 Labor Escalation (use updated estimate)	4.20%
1992 Labor Escalation (use updated estimate of CPI-Wage Earners)	4.80%
Labor Base for AY 1992 in 1992$	306,801
Labor Escalation for AY 1992 in 1992$	14,052
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009638
Increase in Revenue Requirement	$14,187

Non-Labor Base

Non-Labor Base for AY 1991 (Adopted in AY1989)	$175,990
1991 Non-Labor Escalation (estimated in GRC)	5.27%
1990 Non-Labor Escalation (estimated in AY1989)	4.83%
1990 Non-Labor Escalation (use recorded)	4.83%
1991 Non-Labor Escalation (use updated estimate)	5.27%
1992 Non-Labor Escalation (use updated estimate)	5.46%
NonLabor Base for AY 1992 in 1992$	185,599
Non-Labor Escalation for AY 1992 in 1992$	9,609
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009638
Increase in Revenue Requirement	$9,702

Depreciation Exp. (Juris. Alloc. Factor 1.0000)

System avg. Depreciation Rate (Adopted in GRC)	4.7061%
Increase in Wtd. Avg. Plant in Service for AY1992 (Adopted in GRC)	327,533
Increase in Depreciation expense	15,414
Increase in Depreciation expense (Calif.)	15,414
Net-to-Gross Multiplier (Adopted in GRC)	1.688446
Increase in Revenue Requirement	$26,025

Ad Valorem Taxes (Juris. Alloc. Factor 1.0000)

System avg. Ad Valorem Tax Rate (Adopted in GRC)		0.5607%
Increase in AY1992 EOY Plant in Service from AY1991 EOY Plant in Service (Adopted in GRC)		337,083
Increase in Ad Valorem Taxes		1,890
Increase in Ad Valorem Taxes (Calif.)		1,890
Uncoll. & Franchise Fee Factor (Adopted in GRC)		1.009638
Increase in Revenue Requirement		$1,908

State Tax Depr. (Juris. Alloc. Factor = 1.0000)

State Tax Depr. Rate (Adopted in GRC)		3.3977%
Increase in AY1992 EOY Plant in Service from AY1991 EOY Plant in Service (Adopted in GRC)		337,083
Increase in State Tax Deprecition		11,453
Increase in State Tax Depreciation (Calif.)		11,453
Increase in CCFT (Tax Rate =	9.3000%	(1,065)
Increase in FIT (Tax Rate =	34.0000%	362
Increase in State & Federal Taxes		(703)
Net-to-Gross Multiplier (Adopted in GRC)		1.688446
Increase in Revenue Requirement		($1,187)

Federal Tax Depr. (Juris. Alloc. Factor 1.0000)

Federal Tax Depr. Rate (Adopted in GRC)		2.9756%
Increase in AY1992 EOY Plant in Service from AY1991 EOY Plant in Service (Adopted in GRC)		337,083
Increase in Federal Tax Depreciation		10,030
Increase in Federal Tax Depreciation (Calif.)		10,030
Increase in Federal Taxes (Tax Rate	34.0000%	(3,410)
Net-to-Gross Multiplier (Adopted in GRC)		1.688446
Increase in RevenueRequirement		($5,758)

Rate Base (Juris. Alloc. Factor = 1.0000)

Wtd. avg. Depr Rate Base for AY1991 (Adopted in GRC)	$2,290,691
Plant in Service (Adopted in GRC)	
Wtd. avg. Additions for AY1991	(142,989)
Net Additions for AY1991	319,810
Wtd. avg. Additions for AY1992	150,712
Plant Held for Future Use (Adopted in GRC)	
Wtd. avg. Additions for AY1991	0
Net Additions for AY1991	0
Wtd. avg. Additions for AY1992	0
Deferred ITC (Adopted in GRC)	
Wtd. Avg. Deferred ITC for TY1990	60,185
Wtd. Avg. Deferred ITC for AY1991	(57,412)
Depreciation Reserve (Adopted in GRC)	
Wtd. avg. Depreciation Reserve for AY1991	1,900,851
Wtd. avg. Depreciation Reserve for AY1992	(2,078,376)
Taxes Deferred - ACRS (Adopted in GRC)	
Wtd. avg. Deferred Taxes - ACRS for AY1991	139,043
Wtd. avg. Deferred Taxes - ACRS for AY1992	(158,335)
Wtd. avg. Depr Rate Base for AY1992	$2,424,179

Wtd. avg. Depr. Rate Base in Attrition Year 1991	$2,290,691
Wtd. avg. Depr. Rate Base in Attrition Year 1992	$2,424,179
Wtd. avg. Depr. Rate Base in AY 1991 (Calif.)	$2,290,691
Wtd. avg. Depr. Rate Base in AY 1992 (Calif.)	$2,424,179

Long-term Debt

Return on Debt in AY 1991 (Adopted in AY1991)	9.32%
Debt capitalization in AY 1991 (Adopted in AY1991)	47.00%
Wtd. cost of Debt for Attrition Year 1991	4.38%
Return on Debt in AY 1992 (Adopted in AY1992)	9.32%
Debt capitalization in AY 1992 (Adopted in AY1992)	47.00%
Wtd. cost of Debt for Attrition Year 1992	4.38%
Increase in Debt cost in Attrition Year 1992	5,847
Uncoll. & Franchise Fee Factor (Adopted in GRC)	1.009638
Increase in Revenue Requirement	$5,903

Preferred Stock

Return on Pref. Stock in AY 1991 (Adopted in AY1991)	8.79%
Pref.Stk. capitalization AY 1991 (Adopted in AY1991)	6.25%
Wtd. cost of Preferred Stock for Test Year 1991	0.55%
Return on Pref. Stock in AY 1992 (Adopted in AY1992)	8.79%
Pref.Stk. capitalization AY 1992 (Adopted in AY1992)	6.25%
Wtd. cost of Preferred Stock for Att. Year 1992	0.55%
Incease in Pref. Stock cost in Att. Year 1992	734
Net-to-Gross Multiplier (Adopted in GRC)	1.688446
Increase in Revenue Requirement	$1,240

Common Equity

Return on Com. Eq. in AY 1991 (Adopted in AY1991)	12.90%
Com. Eq. capitalization AY 1991 (Adopted in AY1991)	46.75%
Wtd. cost of Common Equity for Test Year 1991	6.03%
Return on Com. Eq. in AY 1992 (Adopted in AY1992)	12.90%
Com. Eq. capitalization AY 1992 (Adopted in AY1992)	46.75%
Wtd. cost of Common Equity for Att. Year 1992	6.03%
Increase in Common Equity cost in Att. Year 1992	8,049
Net-to-Gross Multiplier (Adopted in GRC)	1.688446
Increase in Revenue Requirement	$13,591

RATEBASE TRACKING

Wtd. avg. Depr.Rate Base in TY1990 (Adopted in GRC)	$2,137,560
Wtd. avg. Depr.Rate Base in TY1990 (estimated at the time of filing for AY 1991)	$2,137,560
Wtd. avg. Depr.RateBase in TY1990 (recorded)	$2,137,560
Wtd. avg. Depr.RateBase in AY1991 (Adopted in GRC)	$2,290,691
Wtd. avg. DeprRateBase in AY1991 (estimated at the time of filing for AY 1991)	$2,290,691
Wtd. avg. Depr.RateBase in AY1991 (use updated est.)	$2,290,691
Wtd. avg. Depr.RateBase in AY1992 (Adopted in GRC)	$2,424,179
Wtd. avg. Depr.RateBase in AY1992 (use updated est.)	$2,424,179

PACIFIC GAS AND ELECTRIC COMPANY
Gas Department
REVENUE REQUIREMENTS FOR ATTRITION YEAR 1992
Thousands Of 1992$

ITEM	ATTRITION YEAR 1992
O & M EXPENSES :	
Labor Escalation	$14,187
Non-Labor Escalation	9,702
Total O&M Expenses	$23,889
CAPITAL RELATED ITEMS :	
Book Depreciation Expenses	26,025
Ad Valorem Taxes	1,908
State Tax Depreciation	(1,187)
Federal Tax Depreciation	(5,758)
Debt cost	5,903
Preferred Stock cost	1,240
Common Equity cost	13,591
Total Capital Related Items	$41,722
OTHER AUTHORIZED ITEMS :	
Abandoned Project Amortization Adjustment	0
Non-recurring O&M Adjustment	0
Total Other Authorized Items	$0
ADD'L REVENUE REQUIREMENTS ---->	$65,612
Exclude % attributable to Large Light & Power (To be adopted in OIR 86-10-001)	0.00%
TOTAL ADD'L REVENUE REQUIREMENTS ---->	$65,612

(END OF APPENDIX F)

APPENDIX C
PAGE 1

PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED REVENUE ALLOCATION
EFFECTIVE JANUARY 1, 1990 1/

CUSTOMER GROUP	SALES 2/ (GWH)	PRESENT RATE REV 3/ ($000s)	TOTAL MC REVS	FULL EPMC	(%) CHANGE	CAPPED EPMC 4/	% OF EPMC ALLOC	(%) CHANGE	ALLOCATION W/LIRA 5/	(%) CHANGE	AVERAGE RATE (C/KWH)
RESIDENTIAL	23,493	2,314,664	1,867,666	2,487,950	7.5	2,487,354	100	7.5	2,476,588	7.0	10.54
SMALL	7,390	764,127	637,709	852,839	11.6	851,348	100	11.4	855,131	11.9	11.57
MEDIUM	12,589	1,133,946	842,964	1,127,484	(0.6)	1,150,091	102	1.4	1,156,526	2.0	9.19
LARGE											
E-19	4,234	343,374	274,652	367,199	6.9	367,111	100	6.9	369,310	7.6	8.72
E-20	14,187	938,856	740,085	956,819	1.9	956,583	100	1.9	963,950	2.7	6.79
SPECIAL CONTRACT	2,171	103,543	0	0	N/A	103,543	N/A	0.0	103,543	0.0	4.77
AGRICULTURE	3,091	280,982	319,386	429,872	53.0	304,389	71	8.3	305,995	8.9	9.90
STREETLIGHTING	273	37,957	15,946	35,030	(7.7)	36,774	105	(3.1)	36,780	(3.1)	13.48
TOTAL	67,428	5,917,449	4,698,408	6,257,192	5.7	6,257,192		5.7	6,267,823	5.9	9.30

1/ Facilities charges, optional TOU meter charges and other non-allocated revenue are excluded from the revenue allocation process. These amounts are included in figures in this table to obtain the correct percentage increase and average rate calculations.

2/ Sales figures are adjusted for employee discounts.

3/ LIRA discounts of $21.73 million are not reflected in residential present rate revenue. Residential revenue is $2.291 billion and total present rate retail revenue is $5.894 billion with this adjustment.

4/ The percentage increase in allocable revenue is 6.4%, rather than the system increase of 5.7%. The difference is due to non-allocated revenue, such as load management credits.

5/ The LIRA surcharge is excluded from the revenue allocation process, and added to intraclass allocations. LIRA discounts are subtracted from the residential allocation. When LIRA discounts are excluded from present rate revenue, the residential increase is 8%.

APPENDIX G
PAGE 2
INTRA-CLASS REVENUE ALLOCATION
TO TARIFF SCHEDULES 1/ 2/ 3/

Pacific Gas and Electric Company

CUSTOMER CLASS & AVG. RATE	TARIFF SCHEDULE	SALES (MkWh)	PRESENT REV. ($000s)	ADOPTED REVENUE($000s)	AVG. RATE/kWh	CHANGE FROM PRESENT RATES
Residential	Schedule E-1	22,679,833	$2,254,115	$2,432,039	$0.10723	7.89%
$0.10678	Schedule E-7	669,286	$55,131	$60,377	$0.09021	9.52%
	Schedule E-8 Load Mgmt.	143,820	$15,754	$16,203	$0.11266	2.85%
Small Light & Power	Schedule A-1	7,171,938	$743,193	$832,631	$0.11610	12.03%
$0.11568	Schedule A-6	111,999	$10,308	$11,028	$0.09846	6.98%
	Schedule A-15	2,112	$288	$336	$0.15902	16.80%
	Schedule TC-1	103,959	$10,051	$10,696	$0.10288	6.42%
	Schedule S		$62	$201	n/a	222.61%
Medium Light & Power	Schedule A-10	9,347,586	$874,018	$904,134	$0.09672	3.45%
$0.09183	Schedule A-11	3,241,865	$259,303	$251,693	$0.07764	-2.93%
	Schedule S		$154	$235	n/a	52.58%
Large Light & Power	Sched E19-T Firm	5,026	$300	$338	$0.06728	12.68%
(500 - 1000 kW)	E19T NonFirm	0	$0	$0		
$0.08706	Sched E19-P Firm	400,138	$27,555	$30,661	$0.07663	11.27%
	E19P NonFirm	15,845	$923	$1,057	$0.06668	14.50%
	Sched E19-S Firm	3,752,129	$309,220	$331,150	$0.08826	7.09%
	E19S NonFirm	40,747	$2,830	$3,242	$0.07956	14.57%
	Schedule A-RTP	20,539	$1,448	$1,579	$0.07687	9.03%
	Schedule S		$344	$637	n/a	85.29%
Large Light & Power	E20/24/25-T Firm	1,661,089	$93,050	$91,392	$0.05502	-1.78%
& Railway	E20-T NonFirm	1,029,558	$47,004	$49,736	$0.04831	5.81%
(Over 1000 kW)	E20/24/25-P Firm	4,722,628	$308,771	$330,233	$0.06993	6.95%
$0.06552	E20-P NonFirm	1,774,237	$98,507	$108,376	$0.06108	10.02%
	E20/24/25-S Firm	4,227,292	$330,241	$328,900	$0.07780	-0.41%
	E20-S NonFirm	652,453	$42,361	$42,792	$0.06559	1.02%
	Schedule A-RTP	119,343	$8,303	$8,572	$0.07182	3.24%
	Schedule S		$4,132	$8,138	n/a	96.97%
	Specl Contracts	2,170,790	$103,543	$103,543	$0.04770	0.00%
Agriculture	Schedule AG-1A	226,411	$35,351	$38,718	$0.17101	9.53%
$0.09805	Schedule AG-RA	26,600	$2,644	$2,901	$0.10908	9.74%
	Schedule AG-VA	66,114	$6,019	$6,608	$0.09995	9.79%
	Schedule AG-4A	130,501	$12,400	$13,611	$0.10430	9.76%
	Schedule AG-5A	79,660	$6,550	$6,757	$0.08482	3.16%
	Schedule AG-1B	560,998	$66,070	$72,429	$0.12911	9.63%
	Schedule AG-RB	39,718	$4,059	$4,453	$0.11212	9.73%
	Schedule AG-VB	30,987	$3,089	$3,390	$0.10939	9.74%
	Schedule AG-4B/C	448,256	$40,635	$44,613	$0.09953	9.79%
	Schedule AG-5B/C	1,481,756	$101,260	$109,605	$0.07397	8.24%
Streetlight Energy $0.07396						

1/ Revenue excludes optional TOU meter charges, submeter discounts, facilities charges, and other adjustments.
2/ Some non-firm classes are capped so that the class revenue allocation including credits does not exceed the intraclass cap. Since rate credits are not included in the allocated amount, some non-firm classes appear to, but do not, exceed the intraclass cap.
3/ LIRA revenues are included. LIRA discounts are excluded from residential revenues.

APPENDIX G
PAGE 3
PACIFIC GAS AND ELECTRIC COMPANY
CALCULATION OF LOW INCOME RATEPAYER ASSISTANCE SURCHARGE

Line No.	Description	Baseline	Non-Baseline	Total
	LIRA Program Costs:			
	1990 Low Income Ratepayer Assistance Discount (cents/kwh):			
1	Residential rate	8.830	13.472	
2	Percent Discount	15%	15%	
3	Low Income Discount (cents/kwh) (Line 1 * Line 2)	1.325	2.021	
4	Low Income Discount Sales (Mwh)	1,007,520.98	476,091.12	1,483,612.10
5	Low Income Discount ($000) (Line 3 * Line 4 / 100)	13,345.16	9,620.50	22,965.66
	November and December 1989 Low Income Ratepayer Assistance Discount (cents/kwh):			
6	Present residential rate	8.118	12.739	
7	Percent Discount	15%	15%	
8	Low Income Discount (cents/kwh)	1.218	1.911	
9	Low Income Discount Sales (Mwh)	167,920.16	79,348.52	247,268.68
10	Low Income Discount ($000)	2,044.76	1,516.23	3,561.00
11	TOTAL DISCOUNTS ($000)	15,389.92	11,136.73	26,526.65
	ADMINISTRATIVE COSTS ($000):			
12	1990 Administrative Budget			4,490.10
13	Plus FF&U (Factor of 1.00865)			38.84
14	1989 Administrative Budget			1,870.87
15	Plus FF&U (Factor of 1.00865)			16.18
16	Total Administrative Costs ($000) (Line 12 + Line 13 + Line 14 +Line 15)			6,415.99
17	Total LIRA Program Costs (Line 11 + Line 16)			32,942.65
	GWH SALES SUBJECT TO LIRA Surcharge			
18	Total Forecast Sales			67,534.0
	Adjustments:			
19	EE Adjustment			63.1
20	Low-income forecast period sales (Line 4)			1,483.6
21	Street Light Sales (LS-1, LS-2, LS-3, TC-1)			384.0
22	Special Contract Sales			2,170.8
23	Total Adjustments			4,101.5
24	Total GWH Sales Subject to LIRA Surcharge			63,432.6
	CALCULATION OF THE LIRA Surcharge:			
25	Total LIRA Program Costs (000)			32,942.65
26	Total GWH Sales Subject to LIRABF			63,432.56
27	LIRA surcharge (cents/kwh) ((Line 25/Line 26)/10)			0.052

(END APPENDIX G)

APPENDIX H
PAGE 1

PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF ADOPTED MARGINAL COSTS
Test Year 1990

MARGINAL ENERGY COSTS	(C/KWH)
Generation	3.551
Transmission	3.596
Distribution:	
Primary	3.717
Secondary	3.795

MARGINAL CAPACITY COSTS	($/KW/YEAR)
Generation	56.17
Transmission	31.80
Distribution:	
Primary	53.00
Secondary	6.87

MARGINAL CUSTOMER COSTS	($/CUSTOMER/YEAR)
Residential	100.37
Small light and power	265.06
Medium light and power: secondary	1278.83
Medium light and power: primary	1533.36
E-19: secondary	11574.47
E-19: primary	9982.09
E-20: secondary	14800.29
E-20: primary	8013.22
E-19 and E-20: transmission	50207.82
Agriculture	483.83
Streetlighting	187.20

PACIFIC GAS AND ELECTRIC COMPANY
MARGINAL GENERATION COST
Test Year 1990

		1990$/KW/YR
1	Combustion Turbine Investment	$443.00
2	General plant loading factor (L1 * 2.1%)	9.30
3	Subtotal (L1 + L2)	452.30
4	ANNUALIZED COST (L3 * 11.07%)	50.07
5	Operations and maintenance expense	3.78
6	Administrative and general loading (L5 * 36.26%)	1.37
7	Annualized working cash ((\[L3 * .9%\] + \[L5 + L6 * 2.44%\]) * 11.07%)	0.46
8	TOTAL ANNUALIZED COST (L4 through L8)	55.69
8a	Adjusted for franchise fees and uncollectibles (L8 * 1.00865)	56.17
8b	Adjusted for ERI of .418 (L8a * .418)	23.48

APPENDIX H
PAGE 2a

PACIFIC GAS AND ELECTRIC COMPANY
ENERGY RELIABILITY INDEX (ERI)
Test Year 1990

1990	0.400
1991	0.434
1992	0.400
1993	0.400
1994	0.420
1995	0.454
6 year average	0.418

APPENDIX H
PAGE 3

PACIFIC GAS AND ELECTRIC COMPANY
MARGINAL TRANSMISSION COST
Test Year 1990

		1990$/KW/YR
1	Transmission investment	$272.00
2	General plant loading factor (L1 * 3.69%)	10.04
3	Subtotal (L1 + L2)	282.04
4	ANNUALIZED COST (L3 * 9.46%)	26.68
5	Operations and maintenance expense	3.37
6	Administrative and general loading (L5 * 36.26%)	1.22
7	Annualized working cash ((\[L3 * .9%\] + \[L5 + L6 * 2.44%\]) * 9.46%)	0.25
8	TOTAL ANNUALIZED COST (L4 through L8)	31.52
8a	Adjusted for franchise fees and uncollectibles (L8 * 1.00865)	31.80

APPENDIX H
PAGE 4

PACIFIC GAS AND ELECTRIC COMPANY
MARGINAL PRIMARY DISTRIBUTION COST
Test Year 1990

		1990$/KW/YR
1	Primary distribution investment	$377.00
2	General plant loading factor (L1 * 9.21%)	34.72
3	Subtotal (L1 + L2)	411.72
4	ANNUALIZED COST (L3 * 10.85%)	44.67
5	Operations and maintenance expense	6.61
6	Administrative and general loading (L5 * 36.26%)	2.40
7	Annualized working cash (((L3 * .9%) + (L5 + L6 * 2.44%)) * 10.85%)	0.43
8	TOTAL ANNUALIZED COST (L4 through L8)	54.10
8a	Less adjustment for customer contributions (3.45% * (L4 + L7))	(1.56)
8b	Adjusted for franchise fees and uncollectibles	53.00

PACIFIC GAS AND ELECTRIC COMPANY
MARGINAL SECONDARY DISTRIBUTION COST
Test Year 1990

		1990$/KW/YR
1	Primary distribution investment	$43.00
2	General plant loading factor (L1 * 9.21%)	3.96
3	Subtotal (L1 + L2)	46.96
4	ANNUALIZED COST (L3 * 10.85%)	5.10
5	Operations and maintenance expense	1.22
6	Administrative and general loading (L5 * 36.26%)	0.44
7	Annualized working cash ((([L3 * .9%] + [L5 + L6 * 2.44%]) * 10.85%)	0.05
8	TOTAL ANNUALIZED COST (L4 through L8)	6.81
8a	Adjusted for franchise fees and uncollectibles (L8 * 1.00865)	6.87

APPENDIX H
PAGE 6
SUMMARY OF MARGINAL ENERGY COSTS
including adders and losses

c/kwh

	SUMMER			WINTER		
	On-Peak	Partial Peak	Off Peak	Partial Peak	Off Peak	Annual
1 Generation Level Marginal Energy Costs includes geothermal adder	3.770	2.910	2.690	3.090	2.520	2.836
2 Variable O&M	0.170	0.130	0.120	0.150	0.150	0.144
3 Marginal Energy Cost (L.1+L.2)	3.940	3.040	2.810	3.240	2.670	2.980
4 Cash Working Capital (L.3*2.44%)	0.096	0.074	0.069	0.079	0.065	0.073
5 Revenue Requirement for Cash Working Capital (L.4*15.69%)	0.015	0.012	0.011	0.012	0.010	0.468
6 Total Marignal Energy Cost (L.3+L.4+L.5)	4.051	3.126	2.889	3.331	2.745	3.520
7 Total Marginal Energy Cost including Franchise & Uncollectibles rates (L.6*1.00865)	4.086	3.153	2.914	3.360	2.769	3.551
Transmission Level						
8 Energy Losses	1.0162	1.0124	1.0130	1.0127	1.0113	1.0126
9 Marginal Energy Cost (L.7*L.8)	4.152	3.192	2.952	3.403	2.801	3.596
Primary Level						
10 Energy Losses	1.0469	1.0381	1.0290	1.0441	1.0271	1.0337
11 Marginal Energy Cost (L.9*L.10)	4.347	3.314	3.038	3.553	2.876	3.717
Secondary Level						
12 Energy Losses	1.0363	1.0253	1.0152	1.0327	1.0142	1.0210
13 Marginal Energy Cost (L.11*L.12)	4.504	3.397	3.084	3.669	2.917	3.795

(END APPENDIX H)

APPENDIX I

PACIFIC GAS AND ELECTRIC COMPANY

RATE DESIGN APPENDIX

NOTE: Rates in this appendix reflect CPUC reimbursement fee of $.00012/kwh, as well as LIRA surcharge of $.00052/kwh for applicable rate schedules.

APPENDIX I

PACIFIC GAS & ELECTRIC COMPANY
EFFECTIVE 01-01-90

Rate Component	ADOPTED RATES SUMMER	WINTER
	($/KWH, $/KW, $/CUSTOMER MONTH)	
RESIDENTIAL		
E-1 a/		
Tier 1 Energy	$0.08882	$0.08882
Tier 2 Energy	$0.13524	$0.13524
Minimum Charge	$5.00	$5.00
EL-1		
Tier 1 Energy	$0.07506	$0.07506
Tier 2 Energy	$0.11451	$0.11451
Minimum Charge	$4.25	$4.25
E-7 and EL-7 b/		
On-Peak Energy	$0.28296	$0.11288
Off-Peak Energy	$0.09199	$0.08034
Baseline Credit	$0.03691	$0.03691
Minimum Energy Charge	$5.00	$5.00
Meter Charge	$4.40	$4.40
Master meter credits (per unit per month)		
Electric--ET	$10.25	
Electric--ES	$2.56	
Gas--GT	$6.32	
Gas--GS	$3.50	

SCHEDULE CHANGES:

Schedules ET and ETL:

1. A minimum average rate of no lower than $.04657 per kwh will apply.

2. MINIMUM RATE LIMITER: Your bills will be controlled by a minimum rate limiter. Your bill will be increased if necessary so that your average rate during any month is not less than the minimum rate limiter shown on this schedule.

For Schedule ETL, the minimum rate limiter will be computed before the LIRA discount is applied to the bill.

NOTES:

a/ The Tier I (baseline) rate is 94.6% of the system average rate. The Tier II rate is 52% higher than the Tier I rate.

b/ Meter charge waived for EL-7.

APPENDIX I
PAGE 2
ADOPTED RESIDENTIAL RATES

Schedule E-8

APPLICABILITY:
This voluntary schedule is available to customers who qualify for service on Schedules E-1, EL-1, E-7 or EL-7.

TERRITORY:
The entire territory served.

RATES:

	Per meter per month	
CUSTOMER CHARGE	$13.92	
	Summer	Winter
ENERGY CHARGE (per kwh):	$0.13892	$0.06805

SPECIAL CONDITIONS:

1. The summer season is May 1 through October 31. The winter season is November 1 through April 30. When billing includes use in both the summer and winter season, charges will be prorated based upon the number of days in each period.

2. Customers who enroll on this schedule during the winter season may not switch to another residential schedule until service has been taken on this schedule for 12 billing periods.

3. The baseline quanitities, rates and additional quantity allowances for medical needs available under other residential rate schedules are not available on this schedule.

APPENDIX I
PAGE 3

PACIFIC GAS AND ELECTRIC COMPANY
RESIDENTIAL BASELINE QUANTITIES
Test Year 1990

SCHEDULE	E-1, E-S, E-T, E-7 (and low-income)						EM (and low-income)					
SEASON	SUMMER			WINTER			SUMMER			WINTER		
BASIC QUANTITY (KWH) TERRITORY	CURRENT MONTHLY	TARGET MONTHLY	TARGET DAILY	CURRENT MONTHLY	TARGET MONTHLY	TARGET DAILY	CURRENT MONTHLY	TARGET MONTHLY	TARGET DAILY	CURRENT MONTHLY	TARGET MONTHLY	TARGET DAILY
P	402	417	13.6	353	320	10.6	221	221	7.2	232	211	7.0
Q	233	236	7.7	341	353	11.7	202	166	5.4	211	217	7.2
R	451	481	15.7	353	356	11.8	291	288	9.4	220	208	6.9
S	402	417	13.6	353	353	11.7	221	221	7.2	181	184	6.1
T	233	236	7.7	262	272	9.0	202	166	5.4	232	190	6.3
V	273	270	8.8	302	302	10.0	172	166	5.4	202	193	6.4
W	503	524	17.1	332	344	11.4	340	316	10.3	211	214	7.1
X	322	328	10.7	341	353	11.7	190	193	6.3	211	217	7.2
Y	261	273	8.9	353	320	10.6	181	205	6.7	232	211	7.0
Z	202	193	6.3	302	320	10.6	132	126	4.1	202	196	6.5
ALL ELECTRIC QUANTITY TERRITORY												
P	610	607	19.8	1122	1053	34.9	451	426	13.9	821	606	20.1
Q	451	359	11.7	851	766	25.4	340	282	9.2	691	673	22.3
R	650	669	21.8	920	902	29.9	472	491	16.0	582	564	18.7
S	610	607	19.8	1023	983	32.6	451	426	13.9	643	573	19.0
T	451	359	11.7	691	673	22.3	340	282	9.2	600	528	17.5
V	531	485	15.8	833	739	24.5	371	301	9.8	561	480	15.9
W	742	754	24.6	920	911	30.2	650	567	18.5	772	676	22.4
X	411	414	13.5	851	766	25.4	313	359	11.7	691	673	22.3
Y	451	460	15.0	1122	1053	34.9	340	445	14.5	821	606	20.1
Z	543	362	11.8	1083	1023	33.9	371	245	8.0	790	827	27.4

SCHEDULE	G-1, G-S, G-T, G-10 (and low-income)						GM (and low-income)					
GAS QUANTITY (THERMS) TERRITORY												
P	18	18	0.6	94	60	2.0	15	15	0.5	82	36	1.2
Q	37	25	0.8	84	69	2.3	31	25	0.8	72	33	1.1
R	18	15	0.5	84	60	2.0	15	18	0.6	72	57	1.9
S	18	18	0.6	84	63	2.1	15	15	0.5	72	33	1.1
T	37	25	0.8	63	60	2.0	31	25	0.8	54	48	1.6
V	46	25	0.8	84	57	1.9	40	21	0.7	72	45	1.5
W	18	18	0.6	66	60	2.0	15	12	0.4	54	39	1.3
X	25	21	0.7	84	69	2.3	18	15	0.5	72	33	1.1
Y	37	21	0.7	94	60	2.0	34	21	0.7	81	36	1.2

APPENDIX I

PAGE 4

PACIFIC GAS & ELECTRIC COMPANY

EFFECTIVE 01-01-90

Rate Component	ADOPTED RATES SUMMER	WINTER
	($/KWH, $/KW, $/CUSTOMER MONTH)	
SMALL AND MEDIUM POWER		
A-1		
Energy Charge	$0.12150	$0.09986
Customer Chg: Single Ph	$7.50	$7.50
Customer Chg: PolyPhase	$8.75	$8.75
A-6		
On-Peak Energy	$0.27871	
Partial-Peak Energy	$0.13935	$0.07434
Off-Peak Energy	$0.07247	$0.05575
Customer Chg: Single Ph	$7.50	$7.50
Customer Chg: PolyPhase	$8.75	$8.75
Meter Charge	$6.20	$6.20
A-15		
Energy Charge	$0.12992	$0.11599
Customer Charge	$7.50	$7.50
Facility Charge	$7.80	$7.80
TC-1		
Energy Charge	$0.09606	$0.09606
Customer Charge	$7.50	$7.50
A-10		
Energy Charge	$0.09407	$0.07290
Demand Charge	$3.30	$3.30
Customer Charge	$63.00	$63.00
Transmsn Voltg Discount	$2.60	$2.60
Primry Voltage Discount	$0.70	$0.70
A-11		
On-Peak Energy	$0.10344	
On-Peak Demand	$9.20	
Partial-Peak Energy	$0.07904	$0.05941
Off-Peak Energy	$0.05305	$0.05145
Maximum Demand	$3.30	$3.30
Customer Charge	$63.00	$63.00
Transmsn Voltg Discount	$2.60	$2.60
Primry Voltage Discount	$0.70	$0.70
Meter Charge	$5.10	$5.10

APPENDIX I
PACIFIC GAS AND ELECTRIC COMPANY
EFFECTIVE 01-01-90

SCHEDULE E-14--EXPERIMENTAL CURTAILABLE RESTRICTED VARIABLE-PEAK-PERIOD TIME-OF-USE SERVICE TO WATER AGENCIES

APPLICABILITY: This is an experimental nonfirm-service schedule for customers whose service otherwise qualifies for Schedule A-10 and whose Standard Industrial Classification (SIC) code is 4941 (water supply) or 4952 (sewerage systems).

Schedule E-14 applies to both single-phase and polyphase alternating-current service (for definitions of those terms, see Section D of Rule 2). Service under this schedule is provided at the sole option of PG&E based upon the availability of metering equipment. Schedule E-14 is limited to 500 customer accounts.

MAXIMUM DEMAND ALLOWED: Under Schedule E-14, there is a limit on the number of kilowatts (kw) the customer may require from the PG&E system. If the customer's demand reaches or exceeds 500 kw for three consecutive months, the account will be transferred to another applicable rate schedule.

MINIMUM REQUIRED SUMMER DEMAND: To qualify for Schedule E-14, the customer must have had an average summer demand of at least 250 kw during each of the six summer billing months preceding its application to take this type of service. Customers who have not yet had six months of summer service must demonstrate to PG&E's satisfaction that they will maintain an average summer demand of 250 kw or more.

The designated number of kw to which the customers are willing to cut back is the customer's "firm service level." The number designated as a firm-service level must be at least 200 kw below the lowest of the customer's average summer demands for the last six summer billing months preceding the designation.

GENERATOR REQUIREMENT: The customer's facility must have generating capacity of 200 kw. Exceptions can be made to the generation provision if PG&E determines that the facility is capable of sustaining curtailments during the peak-period for five consecutive days. If the customer wishes to operate its generator(s) in parallel with the PG&E system it must follow PG&E's Electric Rule 21.

TRANSFERS OFF SCHEDULE E-14: If the facility fails to meet either the maximum summer demand or generation criteria for a three-month period of time, PG&E will transfer the account from E-14 to a different applicable rate schedule.

Definition of Maximum Demand: Demand will be averaged over 30-minute intervals. "Maximum demand" will be the highest of all the 30-minute averages for the billing month. If the customer's use of electricity is intermittent or subject to violent fluctuations, a 5-minute or 15-minute interval may be used instead of the 30-minute interval. If the customer has any welding machines, the diversified resistance welder load, calculated in accordance with Section J of Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 30-minute intervals. The customer's maximum-peak-period demand will be the highest of all the 30-minute averages for the peak period during the billing month. (See Section 5 for a definition of "Peak-Period.")

TERRITORY: PG&E's entire service territory.

RATE:

	Per Month	
CUSTOMER CHARGE (per meter per month):	$63.00	
METER CHARGE (per meter per month):	$ 5.10	
DEMAND CHARGE (per kw of maximum demand per month): .	$ 3.30	
*ENERGY CHARGE (per kwh):	Summer	Winter
Peak	$0.12784	--
Partial-Peak	$0.07904	$0.05941
Off-Peak	$0.05305	$0.05145
PEAK-PERIOD DEMAND CHARGE (per kw of maximum peak-period demand per month)	$9.20	--

APPENDIX I
PACIFIC GAS AND ELECTRIC COMPANY
EFFECTIVE 01-01-90

SCHEDULE E-14--EXPERIMENTAL CURTAILABLE RESTRICTED VARIABLE-PEAK-PERIOD TIME-OF-USE SERVICE TO WATER AGENCIES

(Continued)

BASIS FOR DEMAND CHARGE: The customer will be billed for its demand according to "maximum demand" each month.

VOLTAGE DISCOUNTS: The customer may be eligible for a discount on the charges shown above if the customer takes delivery of electricity at a voltage level greater than that PG&E normally makes available to customers.

To qualify for a discount, the customer must take service at one of the standard primary or transmission voltages specified in Rule 2.

The voltage discount, if any, will be applied to the Demand Charge.

Discounts are applied in any month as follows:

(1) $2.60 per kw of maximum demand when service is delivered at 50,000 volts or above;

(2) $0.70 per kw of maximum demand when service is delivered at a standard service voltage between 2,000 and 50,000 volts and there is only one stage of transformation between service voltage and PG&E's transmission voltage (50,000 volts or greater).

Voltage discounts will not apply when delivery is made at less than 2,000 volts.

PG&E retains the right to change its line voltage at any time. Customers receiving voltage discounts will get reasonable notice of any impending change. They will then have the option of taking service at the new voltage (and making whatever changes in their systems are necessary) or taking service without a voltage discount through transformers supplied by PG&E.

POWER FACTOR ADJUSTMENT: When the customer's maximum demand has exceeded 400 kw for three consecutive months and thereafter until it has fallen below 300 kw for 12 consecutive months, the bill will be adjusted for weighted monthly average power factor as follows: If the customer's average power factor is greater than 85 percent, the total monthly bill (including any voltage adjustment but excluding any taxes) will be reduced by 0.06 percent for each percentage point above 85 percent. If the average power factor is below 85 percent, the total monthly bill (including any voltage adjustment but excluding any taxes) will be increased by 0.06 percent for each percentage point below 85 percent. Such average power factor will be computed (to the nearest whole percent) from the ratio of lagging reactive kilovolt ampere hours to kilowatt-hours consumed in the month. No power factor correction will be made for any month when the customer's maximum demand is less than 10 percent of the highest such demand in the preceding 11 months.

APPENDIX I
PACIFIC GAS AND ELECTRIC COMPANY
EFFECTIVE 01-01-90

SCHEDULE E-14--EXPERIMENTAL CURTAILABLE RESTRICTED VARIABLE-PEAK-PERIOD TIME-OF-USE SERVICE TO WATER AGENCIES

(Continued)

EMERGENCY CURTAILMENT REQUIREMENT: If a customer takes service under Schedule E-14 it must have at least 200 kw of curtailable load. PG&E will make requests for curtailments from customers on Schedule E-14 when, in PG&E's sole judgement, a systemwide or local operating condition exists which will impair the ability of PG&E to meet the demands of its other customers.

CURTAILMENT LIMITATION: Customers are limited to two six-hour curtailments per year, and must be given at least six hours' notice prior to a curtailment of this length. Customers may also be curtailed up to three hours provided that they are given at least one hour's notice. Curtailments may only occur on 15 days of the calendar year and may not exceed a total of 51 hours annually. Curtailments may only occur between 10:00 a.m. and 8:00 p.m. and notice may not be sent after 4:00 p.m.

There will be no curtailments during the winter season or on weekends and holidays as defined on this schedule.

EMERGENCY CURTAILMENT PROCEDURE: When it becomes necessary for PG&E to request a curtailment, PG&E will notify the customer by telephone or electronic mail. This notification will designate a time by which the customer's demand must be reduced to a specified number of kilowatts.

The customer may not resume the use of curtailed power until notified by PG&E that it may do so or until the customer has curtailed its service for six hours.

TELEPHONE LINE REQUIREMENTS: Non-firm customers are required to make available a telephone line and space for a notification printer. This requirement is in addition to any other equipment requirement which may apply.

EMERGENCY-NOTICE PROVISION: If there is an emergency on the PG&E system, PG&E may ask the customer to curtail the use of electricity on less notice than is usually allowed under the curtailment limitations. The customer will be asked to make the best effort to comply. The customer will not be assessed the noncompliance penalty for failing to comply within the shorter notice period, but the customer will be assessed this penalty if the regular notice period for the option passes and the customer still has not curtailed use.

RATE DISCOUNT: The customer will receive a discount for reducing its load and will also be subject to a penalty for non-compliance. Both the discount and penalty are set at 60 percent of the levels used in PG&E's experimental Small Commercial Industrial Program (SCIP). In the event SCIP is terminated, the discount and penalty levels in effect at that time will remain until tariff revisions are filed by PG&E and approved by the California Public Utilities Commission.

- Discount: The customer's discount is calculated by multiplying 60 percent of the SCIP discount (per kw) times the difference between the customer's firm service level and the customers average peak-period load.

- Penalty: The customer's penalty will be calculated by multiplying 60 percent of the SCIP discount (per kw) times the difference between the customer's average load during a curtailment and its firm service level.

METERING REQUIREMENT: Customers must permit PG&E to install and maintain at PG&E's expense load profile and notification equipment on the customer's premises.

CONTRACT: Service under Schedule E-14 is available on an annual basis only. Contracts will be required from customers whose operations are seasonal.

SPECIAL CONDITIONS: The summer (Period A) rate is applicable May 1 through October 31. The winter (Period B) rate is applicable November 1 through April 30. When Period A and Period B proration is required, charges will be based on the average daily usage for the full billing month times the number of days in each period.

APPENDIX I
PACIFIC GAS AND ELECTRIC COMPANY
EFFECTIVE 01-01-90

SCHEDULE E-14--EXPERIMENTAL CURTAILABLE RESTRICTED VARIABLE-PEAK-PERIOD TIME-OF-USE SERVICE TO WATER AGENCIES

(Continued)

TIME PERIODS: Seasons of the year and times of the day are defined as follows:

SUMMER: Service from May 1 through October 31.

*Peak:			
	Group I	2:00 p.m. to 5:00 p.m.	Monday through Friday**
	Group II	3:00 p.m. to 6:00 p.m.	Monday through Friday**
Partial-Peak:			
	Group I	8:30 a.m. to 2:00 p.m. and 5:00 p.m. to 9:30 p.m.	Monday through Friday
	Group II	8:30 a.m. to 3:00 p.m. and 6:00 p.m. to 9:30 p.m.	Monday through Friday
Off-Peak:		All other hours	Monday through Friday
		All day	Saturday, Sunday, holidays

WINTER: Service from November 1 through April 30.

Partial-Peak:	8:30 a.m. to 9:30 p.m.	Monday through Friday
Off-Peak:	All other hours	Monday through Friday
	All day	Saturday, Sunday, holidays

HOLIDAYS: "Holidays" for the purposes of this rate schedule are New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. The dates will be those on which the holidays are legally observed.

CHANGE FROM SUMMER TO WINTER OR WINTER TO SUMMER: When a billing month includes both summer and winter days, PG&E will calculate demand charges as follows. It will consider the applicable maximum demands for the summer and winter portions of the billing month separately, calculate a demand charge for each, and then apply the two according to the number of billing days each represents.

NOTE: If your meter is read within one work day of the season changeover date (May 1 or November 1), PG&E will use only the rates and charges from the season having the greater number of days in your billing month. Work days are Monday through Friday, inclusive.

*Providing space is available, you may have the option of choosing the applicable peak-period hours.
**Except holidays.

APPENDIX I
PACIFIC GAS AND ELECTRIC
E-19 AND E-20 RATES
PAGE 9

	E-19 Firm Transmission Summer	Winter	E-19 Firm Primary Summer	Winter	E-19 Firm Secondary Summer	Winter
On-Peak Energy	$0.09102		$0.10195		$0.10839	
On-Peak Demand	$7.20		$8.80		$9.40	
Partial-Peak Energy	$0.06178	$0.05282	$0.06920	$0.05916	$0.07357	$0.06290
Off-Peak Energy	$0.04716	$0.04575	$0.05283	$0.05124	$0.05616	$0.05448
Maximum Demand	$0.70	$0.70	$2.60	$2.60	$3.30	$3.30
Customer Charge	$510.00	$510.00	$250.00	$250.00	$280.00	$280.00
Avg. Rate Limit			$0.13330		$0.13330	
On-Peak Rate Limit	$0.57455		$0.78445		$0.78906	

	E-19 Non-Firm Transmission Summer	Winter	E-19 Non-Firm Primary Summer	Winter	E-19 Non-Firm Secondary Summer	Winter
On-Peak Energy	$0.08862		$0.09350		$0.10678	
On-Peak Demand	$1.18		$2.09		$2.26	
Partial-Peak Energy	$0.06015	$0.05143	$0.06347	$0.05426	$0.07248	$0.06197
Off-Peak Energy	$0.04592	$0.04454	$0.04845	$0.04699	$0.05533	$0.05367
Maximum Demand	$0.70	$0.70	$2.60	$2.60	$3.30	$3.30
Customer Charge	$510.00	$510.00	$250.00	$250.00	$280.00	$280.00
Curtailable Svc Chg	$190.00	$190.00	$190.00	$190.00	$190.00	$190.00
UFR Credit / kWh	$0.00186	$0.00186	$0.00186	$0.00186	$0.00186	$0.00186
Excess Energy Charge/kwh/event	$6.77200	$6.77200	$8.64933	$8.64933	$8.64933	$8.64933

	E-20 Firm Transmission Summer	Winter	E-20 Firm Primary Summer	Winter	E-20 Firm Secondary Summer	Winter
On-Peak Energy	$0.07797		$0.09726		$0.09877	
On-Peak Demand	$7.20		$8.80		$9.40	
Partial-Peak Energy	$0.05363	$0.04620	$0.06601	$0.05644	$0.06704	$0.05732
Off-Peak Energy	$0.04125	$0.04002	$0.05039	$0.04888	$0.05118	$0.04964
Maximum Demand	$0.70	$0.70	$2.60	$2.60	$3.30	$3.30
Customer Charge	$510.00	$510.00	$220.00	$220.00	$330.00	$330.00
Avg. Rate Limit			$0.11565		$0.11565	
On-Peak Rate Limit	$0.57455		$0.78445		$0.78906	

	E-20 Non-Firm Transmission Summer	Winter	E-20 Non-Firm Primary Summer	Winter	E-20 Non-Firm Secondary Summer	Winter
On-Peak Energy	$0.07592		$0.08990		$0.09385	
On-Peak Demand	$1.18		$2.09		$2.26	
Partial-Peak Energy	$0.05222	$0.04499	$0.06102	$0.05217	$0.06370	$0.05446
Off-Peak Energy	$0.04017	$0.03896	$0.04658	$0.04518	$0.04863	$0.04717
Maximum Demand	$0.70	$0.70	$2.60	$2.60	$3.30	$3.30
Customer Charge	$510.00	$510.00	$220.00	$220.00	$330.00	$330.00
Curtailable Svc Chg	$190.00	$190.00	$190.00	$190.00	$190.00	$190.00
UFR Credit / kWh	$0.00186	$0.00186	$0.00186	$0.00186	$0.00186	$0.00186
Excess Energy Charge/kwh/event	$6.77200	$6.77200	$8.64933	$8.64933	$8.64933	$8.64933

Customer charges for the non-firm options equal the firm service customer charge plus a $190 meter charge for curtailable service or $200 for interruptible service. Rate limiters do not apply on non-firm options.

APPENDIX I
PACIFIC GAS AND ELECTRIC COMPANY
EFFECTIVE 01-01-90

COMMERCIAL/INDUSTRIAL/GENERAL

SCHEDULE E-19--SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS BETWEEN 499 KILOWATTS AND 1,000 KILOWATTS

CONTENTS:

This rate schedule is divided into the following sections:

1. Applicability
2. Territory
3. Firm service rates
4. Definition of service voltage
5. Definition of time periods
6. Power factor adjustments
7. Charges for transformer losses
8. Standard service facilities
9. Special facilities
10. Arrangements for visual-display metering
11. Non-firm service program
12. Non-firm service rates
13. Economic dispatch curtailment program
14. Phase-in program for continuing non-firm service customers
15. Contracts

1. APPLICABILITY:

Initial Assignment: A customer is eligible for service under Schedule E-19 if: (1) the customer's load does not meet the Schedule E-20 requirements, but, (2) the customer's maximum demand (as defined below) has exceeded 499 kilowatts for at least three consecutive months during the most recent 12-month period.

Customer accounts which fail to qualify under these requirements may, at PG&E's election, be evaluated for transfer to service under a different applicable rate schedule.

Transfers Off of Schedule E-19: If a customer's maximum demand has failed to exceed 499 kilowatts for 12 or more consecutive months, PG&E may transfer that customer's account to service under a different applicable rate schedule.

Assignment of New Customers: If a customer is new and PG&E believes that the customer's maximum demand will be between 499 and 1,000 kilowatts, PG&E will serve the customer's account under Schedule E-19.

Definition of Maximum Demand: Demand will be averaged over 30-minute intervals. "Maximum demand" will be the highest of all the 30-minute averages for the billing month. If the customer's use of electricity is intermittent or subject to violent fluctuations, a 5-minute or 15-minute interval may be used instead of the 30-minute interval. If the customer has any welding machines, the diversified resistance welder load, calculated in accordance with Section J of Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 30-minute intervals. The customer's maximum-peak-period demand will be the highest of all the 30-minute averages for the peak period during the billing month. (See Section 5 for a definition of "Peak-Period.")

Water Agencies: If the customer's service qualifies as a water agency with at least 70 percent of the water pumped on the customer's account going directly to agricultural applications, the customer must take service on an agricultural schedule.

Sections 2 through 14 of Schedule E-19 are identical to the corresponding sections in Schedule E-20. Section 15 (Contracts) of Schedule E-19 is identified to Section 15 of Schedule E-20 with the exception of the low maximum demand, which is 500 kw in Schedule E-19 and 1,000 kw in Schedule E-20.

APPENDIX I
PACIFIC GAS AND ELECTRIC COMPANY
EFFECTIVE 01-01-90

COMMERCIAL/INDUSTRIAL/GENERAL

SCHEDULE E-20--SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE

CONTENTS:

This rate schedule is divided into the following sections:

1. APPLICABILITY:

Initial Assignment: A customer is eligible for service under Schedule E-20 if the customer's maximum demand (as defined below) has exceeded 999 kilowatts for at least three consecutive months during the most recent 12-month period.

Customer accounts which fail to qualify under these requirements may, at PG&E's election, be evaluated for transfer to service under a different applicable rate schedule.

Transfers Off Schedule E-20: If a customer's maximum demand has failed to exceed 999 kilowatts for 8 or more out of the last 12 consecutive billing months and has also failed to exceed 999 kilowatts for three consecutive months during that period, PG&E may transfer that customer's account to service under a different applicable rate schedule.

Assignment of New Customers: If a customer is new and PG&E believes that the customer's maximum demand will exceed 999 kilowatts, PG&E will serve the customer's account under Schedule E-20.

Definition of Maximum Demand: Demand will be averaged over 30-minute intervals. "Maximum demand" will be the highest of all the 30-minute averages for the billing month. If the customer's use of electricity is intermittent or subject to violent fluctuations, a 5-minute or 15-minute interval may be used instead of the 30-minute interval. If the customer has any welding machines, the diversified resistance welder load, calculated in accordance with Section J of Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 30-minute intervals. The customer's maximum-peak-period demand will be the highest of all the 30-minute averages for the peak period during the billing month. (See Section 5 for a definition of "Peak-Period.")

Water Agencies: If the customer's service qualifies as a water agency with at least 70 percent of the water pumped on the customer's account going directly to agricultural applications, the customer must take service on an agricultural schedule.

2. TERRITORY:

Schedule E-20 applies everywhere PG&E provides electricity service.

APPENDIX I
PACIFIC GAS AND ELECTRIC COMPANY
EFFECTIVE 01-01-90

COMMERCIAL/INDUSTRIAL/GENERAL

SCHEDULE E-20--SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE

(Continued)

3. FIRM SERVICE RATES:

Service Voltage:	Secondary (E-20S)		Primary (E-20P)		Transmission (E-20T)	
Season:	Summer	Winter	Summer	Winter	Summer	Winter

a. TYPES OF CHARGES: The customer's monthly charge for service under Schedule E-20 is the sum of a customer charge, demand charges, and energy charges:

- The customer charge is a flat monthly fee.

- Schedule E-20 has two demand charges, a maximum-peak-period-demand charge and a maximum-demand charge. The maximum-peak-period-demand charge per kilowatt applies to the maximum demand during the month's peak hours, and the maximum-demand charge per kilowatt applies to the maximum demand at any time during the month. The bill will include both of these demand charges. (Time periods are defined in Section 5.)

- The energy charge is the sum of the energy charges from the peak, partial-peak, and off-peak periods. The customer pays for energy by the kilowatt-hour (kwh), and rates are differentiated according to time of day and time of year.

- The monthly charges may be increased or decreased based upon the power factor. (See Section 6.)

- As shown on the rate chart, which set of customer, demand, and energy charges is paid depends on the voltage at which service is taken. Service voltages are defined in Section 4 below.

- Please note that the rates in the chart on the preceding page apply only to firm service. Rates for non-firm service can be found in Section 12 of this rate schedule.

b. AVERAGE RATE LIMITER (applies to firm service only): If the customer takes service on Schedule E-20, in either the secondary or primary voltage class, bills will be controlled by a "rate limiter" during the summer months. The bill will be reduced if necessary so that the average rate during a summer month does not exceed the rate limiter shown on this schedule.

APPENDIX I
PACIFIC GAS AND ELECTRIC COMPANY
EFFECTIVE 01-01-90

COMMERCIAL/INDUSTRIAL/GENERAL

SCHEDULE E-20--SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE

(Continued)

3. FIRM SERVICE RATES: (Cont'd.)

c. PEAK-PERIOD RATE LIMITER (applies to firm service only): If the customer takes service on Schedule E-20 at any service voltage level, bills will be controlled by a "peak-period rate limiter" during the summer months. The bill will be reduced if necessary so that the average rate during the peak period in a summer month does not exceed the peak-period rate limiter shown on this schedule.

4. DEFINITION OF SERVICE VOLTAGE:

The following defines the 3 voltage classes of Schedule E-20 rates. Standard Service Voltages are listed in Rule 2.

a. Secondary: This is the voltage class if the service voltage is less than 2,000 volts or if the definitions of "primary" and "transmission" do not apply to the service.

b. Primary: This is the voltage class if the customer is served at a standard service voltage between 2,000 and 50,000 volts, and there is only one stage of transformation between the service voltage and PG&E's transmission voltage (50,000 volts or greater).

c. Transmission: This is the voltage class if the customer is served at a standard service voltage greater than 50,000 volts.

5. DEFINITION OF TIME PERIODS:

Times of the year and times of the day are defined as follows:

SUMMER Period A (service from May 1 through October 31):

Peak:	12:00 noon to 6:00 p.m.	Monday through Friday (except holidays)
Partial-Peak:	8:30 a.m. to 12:00 noon AND 6:00 p.m. to 9:30 p.m. Monday through Friday (except holidays)	
Off-peak:	9:30 p.m. to 8:30 a.m. All day Saturday, Sunday, and holidays.	Monday through Friday

WINTER Period B (Service from November 1 through April 30):

Partial-Peak:	8:30 a.m. to 9:30 p.m.	Monday through Friday, except holidays.
Off-Peak:	9:30 p.m. to 8:30 a.m. All Day	Monday through Friday, except holidays. Saturday, Sunday and holidays.

HOLIDAYS: "Holidays" for the purposes of this rate schedule are New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. The dates will be those on which the holidays are legally observed.

CHANGE FROM SUMMER TO WINTER OR WINTER TO SUMMER: When a billing month includes both summer and winter days, PG&E will calculate demand charges as follows. It will consider the applicable maximum demands for the summer and winter portions of the billing month separately, calculate a demand charge for each, and then apply the two according to the number of billing days each represents. NOTE: If the meter is read within one work day of the season changeover date (May 1 or November 1), PG&E will use only the rates and charges from the season having the greater number of days in the billing month. Work days are Monday through Friday, inclusive.

APPENDIX I
PACIFIC GAS AND ELECTRIC COMPANY
EFFECTIVE 01-01-90

COMMERCIAL/INDUSTRIAL/GENERAL

SCHEDULE E-20--SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE

(Continued)

6. POWER FACTOR ADJUSTMENTS:

The bill will be adjusted based upon the power factor. The power factor is computed from the ratio of lagging reactive kilovolt-ampere-hours to the kilowatt-hours consumed in the month. Power factors are rounded to the nearest whole percent.

The rates in this rate schedule are based on a power factor of 85 percent. If the average power factor is greater than 85 percent, the total monthly bill (excluding any taxes) will be reduced by 0.06 percent for each percentage point above 85 percent. If the average power factor is below 85 percent, the total monthly bill (excluding any taxes) will be increased by 0.06 percent for each percentage point below 85 percent.

7. CHARGES FOR TRANSFORMER LOSSES:

If the electricity used undergoes transformation between PG&E's delivery point and the metering point, the demand and energy meter readings used in determining the charges will be increased to correct for transformer losses. A 2-percent addition will be made for each stage of transformation between PG&E's delivery and metering points.

8. STANDARD SERVICE FACILITIES:

If PG&E must install any new or additional facilities to provide the customer with service under Schedule E-20, the customer may have to pay some of the cost. Any advance necessary and any monthly charge for the facilities will be specified in a facilities charge agreement. See Rules 2, 15, and 16 and the facilities charge agreement form (Form No. 79-245) for details.

Facilities installed to serve the customer may be removed when service is discontinued. The customer will then have to repay PG&E for all or some of its investment in the facilities. Terms and conditions for repayment will be set forth in the facilities charge agreement.

9. SPECIAL FACILITIES:

PG&E will normally install only those standard facilities it deems necessary to provide service under Schedule E-20. If the customer requests any additional facilities, those facilities will be treated as "special facilities" in accordance with Section I of Rule 2.

10. ARRANGEMENTS FOR VISUAL-DISPLAY METERING:

If the customer wishes to have visual-display metering equipment in addition to the regular metering equipment, the customer must submit a written request to PG&E. PG&E will provide and install the equipment within 180 days of receiving the request. The visual-display metering equipment will be installed near the present metering equipment. The customer will be responsible for providing the required space and associated wiring.

PG&E will continue to use the regular metering equipment for billing purposes.

11. NON-FIRM SERVICE PROGRAM:

As noted, the rates in the chart in Section 3 of this rate schedule apply to firm service only. ("Firm" means service where PG&E provides a "continuous and sufficient supply of electricity," as described in Rule 14.) A customer may also elect to receive non-firm service under Schedule E-20.

A customer who elects to receive non-firm service under Schedule E-20 must participate in PG&E's emergency curtailment program. A non-firm service customer may also elect to participate in PG&E's underfrequency relay (UFR) and "economic dispatch" programs.

APPENDIX I
PACIFIC GAS AND ELECTRIC COMPANY
EFFECTIVE 01-01-90

COMMERCIAL/INDUSTRIAL/GENERAL

SCHEDULE E-20--SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE

(Continued)

11. NON-FIRM SERVICE PROGRAM: (Cont'd.)

- EMERGENCY CURTAILMENT PROGRAM: Under the emergency curtailment program, a non-firm service customer may be required to reduce demand to a designated number of kilowatts, referred to as the customer's contractual "firm service level." PG&E will make requests for such curtailments from its non-firm service customers when, in PG&E's sole judgement, a systemwide or local operating condition exists which will impair the ability of PG&E to meet the demands of its other customers.

- UNDERFREQUENCY RELAY PROGRAM: Under this program, the customer agrees to be subject at all times to automatic interruptions of service caused by an underfrequency relay device that may be installed by PG&E.

- ECONOMIC CURTAILMENT PROGRAM: Under this program, a non-firm service customer may occasionally be notified by PG&E of an "economic dispatch" price, quoted in dollars per kilowatt-hour curtailed, that PG&E is electing to offer for voluntary load curtailments. (See Section 13 of this rate schedule for a more complete description of this program.)

See Section 15 of this rate schedule for a discussion of contractual length-of-service requirements that may be applied to customers enrolling in the non-firm service program. Please note that PG&E may require up to three years' written notice for a change from non-firm to firm service, or for termination of participation in the underfrequency relay program.

a. ELIGIBILITY CRITERIA FOR NON-FIRM SERVICE: To qualify for non-firm service, the customer must have had an average peak-period demand of at least 500 kilowatts during each of the last six summer billing months prior to the customer's application for non-firm service. (Average peak-period demand is the total number of kwh used during the peak-period hours of a billing month divided by the total number of peak-period hours in the month.) Customers who have not yet had six months of summer service must demonstrate to PG&E's satisfaction that they will maintain an average monthly-peak-period demand of 500 kw or more to qualify for non-firm service.

b. DESIGNATION OF FIRM SERVICE LEVEL: If a customer takes non-firm service, the designated number of kilowatts to which the customer must reduce demand during emergency curtailments is the customer's contractual "firm service level." This designated firm service level must be at least 500 kilowatts less than the smallest of the customer's average peak-period demands during the last six summer billing months prior to the designation.

c. LIMIT ON EMERGENCY CURTAILMENTS: A customer will be requested to curtail demand, under the emergency curtailment program, no more than 30 times per year and will be given at least 30 minutes notice before each curtailment. Curtailments will not exceed six hours for any individual interruption or 100 hours for the entire year.

d. EMERGENCY CURTAILMENT PROCEDURE: When it becomes necessary for PG&E to request a curtailment, PG&E will notify the customer by telephone or electronic mail. This notification will designate a time by which the customer's demand must be reduced to a specified number of kilowatts. (The specified reduced demand will not be less than the customer's contractual firm service level.)

The customer may not resume the use of curtailed power until notified by PG&E that it may do so or until the customer has curtailed its service for six hours.

APPENDIX I
PACIFIC GAS AND ELECTRIC COMPANY
EFFECTIVE 01-01-90

COMMERCIAL/INDUSTRIAL/GENERAL

SCHEDULE E-20--SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE

(Continued)

11. NON-FIRM SERVICE PROGRAM: (Cont'd.)

e. EXCESS DEMAND CHARGES: If PG&E requests that a non-firm service customer curtail the use of electricity and the customer fails to do so by the time specified, the customer must pay an excess demand charge. This charge will be payable in addition to the regular charges.

The charge will be calculated by determining the total amount of excess energy taken during the curtailment period (energy taken in excess of the customer's firm service level) and multiplying this total times the excess demand charge (per kwh).

The applicable excess demand charges, which vary by service voltage level, are listed in Section 12 of this schedule.

f. EMERGENCY-NOTICE PROVISION: If there is an emergency on the PG&E system, PG&E may ask the customer to curtail the use of electricity on less notice than is usually allowed for the option. The customer will be asked to make the best effort to comply. The customer will not be assessed the noncompliance penalty for failing to comply within the shorter notice period, but the customer will be assessed this penalty if the regular notice period for the option passes and the customer still has not curtailed use.

g. ADDITIONAL NON-FIRM SERVICE PROVISIONS:

(1) **Required Re-Designations of Firm Service Level:** A non-firm service customer must maintain a difference of at least 500 kw between the firm service level and the average monthly summer peak-period demand. If the difference is less than 500 kw for any three summer months during any 12-month period, the customer must designate a new firm service level. This new firm service level must be at least 500 kw below the lowest of the customer's average peak-period demands for the last six summer billing months preceding the new designation. If the customer cannot meet this requirement, PG&E will change the account to firm service.

(2) **Optional Re-Designations of Firm Service Level:** A non-firm service customer may decrease the firm service level effective with the start of any billing month, provided customer gives PG&E at least 30 days' written notice. The customer may increase the firm service level only once a year, by giving PG&E written notice between January 1 and February 1. The increased firm service level must be such that there is still at least a 500-kw difference between the firm service level and the lowest average monthly summer peak-period demand. The increased firm service level will become effective with the first regular reading of the meter on or after February 15.

(3) **Telephone Line Requirements:** Non-firm customers are required to make available a telephone line and space for a notification printer. This requirement is in addition to any other equipment requirement which may apply.

h. BILL REDUCTIONS FOR NON-FIRM SERVICE CUSTOMERS:

(1) **Demand Charges:** Reduced peak-period demand charges for curtailable service shall be applied to the difference between the customer's maximum demand in the peak time period and its Firm Service Level (but not less than zero). The peak-period charges for firm service shall be applied to the peak-period demand less the above difference.

APPENDIX I
PACIFIC GAS AND ELECTRIC COMPANY
EFFECTIVE 01-01-90

COMMERCIAL/INDUSTRIAL/GENERAL

SCHEDULE E-20--SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE

(Continued)

11. NON-FIRM SERVICE PROGRAM: (Cont'd.)

h. BILL REDUCTIONS FOR NON-FIRM SERVICE CUSTOMERS:

(2) **Energy Charges:** Reduced energy charges for curtailable service shall be applied to (a-b), where (a) is the number of kilowatt-hours used in the time period and (b) is the product of the Firm Service Level and the number of hours in the time period. (a-b) shall not be less than zero.

i. PROVISIONS SPECIFIC TO UFR PROGRAM:

(1) **Details on Automatic Interruptions:** If a customer is participating in the UFR program, service to the customer will be automatically interrupted if the frequency on the PG&E system drops to 59.75 hertz for 6 cycles. PG&E will install and maintain a digital underfrequency relay and whatever associated equipment it believes is necessary to carry out such automatic interruption. Relays and other equipment will remain the property of PG&E. If more than one relay is required, PG&E will provide the additional relays as "special facilities," at customer's expense, in accordance with Section I of Rule 2.

In addition to the underfrequency relay, PG&E may install equipment that would automatically interrupt service in case of voltage reductions or other operating conditions.

(2) **Metering Requirements for UFR Program:** If a customer is participating in the UFR program under Schedule E-20 in combination with firm or curtailable-only service, the customer will have to have a separate meter for the UFR service. PG&E will provide the meter sets, but the customer will be responsible for arranging customer's wiring in such a way that the service for each account can be provided and metered at a single point. NOTE: Any other additional facilities required for a combination of curtailable with firm service will be treated as "special facilities" in accordance with Section I of Rule 2.

(3) **Communication Channel for UFR Service:** UFR program customers are required to provide an exclusive communication channel from the PG&E-provided terminal block at the customer's facility to a PG&E-designated control center. The communication channel must meet PG&E's specifications, and must be provided at the customer's expense. PG&E shall have the right to inspect the communication circuit upon reasonable notice.

APPENDIX I
PACIFIC GAS AND ELECTRIC COMPANY
EFFECTIVE 01-01-90

COMMERCIAL/INDUSTRIAL/GENERAL

SCHEDULE E-20--SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE

(Continued)

12. NON-FIRM SERVICE RATES:

These rates are applicable if the customer elects to take non-firm service. See Section 11, for an explanation of the non-firm service program and to see if you are eligible for any of these special-service options.

Service Voltage:	Transmission		Primary		Secondary	
Season:	Summer	Winter	Summer	Winter	Summer	Winter

13. ECONOMIC DISPATCH CURTAILMENT PROGRAM:

Customers electing non-firm service are automatically eligible to participate in PG&E's economic dispatch curtailment program on a voluntary basis. During periods when it is uneconomic for PG&E to supply energy to non-firm service customers, PG&E will offer an economic dispatch price, quoted in dollars per kilowatt-hour curtailed. The price will vary depending on voltage level, and may also vary by day, time period and geographical location. PG&E's offering price is to be based on the forecasted cost of electric power at the time the curtailment is requested.

Customers will have a minimum of 30 minutes advance notice prior to the start of curtailment period. Customers must reduce load to or below the firm service level for the entire requested curtailment period to receive the credit. The credit will equal the quoted economic dispatch price multiplied by the total kilowatt-hours curtailed. Curtailed kilowatt-hours will be calculated by PG&E based upon the difference between actual load and estimated expected load absent the curtailment. The total amount credited will be applied to the bill rendered immediately following PG&E's measurement and verification of the amount of load curtailed.

APPENDIX I
PACIFIC GAS AND ELECTRIC COMPANY
EFFECTIVE 01-01-90

COMMERCIAL/INDUSTRIAL/GENERAL

SCHEDULE E-20--SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE

(Continued)

14. PHASE-IN PROGRAM FOR CONTINUING NON-FIRM SERVICE CUSTOMERS:

If a customer was enrolled in PG&E's non-firm service program prior to December 1, 1989, PG&E will calculate the customer's bills for service after January 1, 1990 using two sets of rates:

a. The rates described in Sections 3 and 12 of this schedule, using the customer's currently applicable service options.

b. The rates for standard (not "extended") non-firm service that were in effect on January 1, 1989, under the curtailment provisions that applied to the account during 1989 at the greater of the firm service levels that applied to the customer's account during 1989.

   This bill calculation will use the 1989 "interruptible service" rate schedule only if the customer participated in the underfrequency relay program during 1989 and is continuing to participate. Otherwise, the 1989 rates for "curtailable service" will be used.

   If (a) exceeds (b) by more than 10 percent, the customer will be billed only for the amount in (b) plus 10 percent. On January 1, 1991, this 10 percent "cap" will be increased to 20 percent. The cap will increase to 30 percent on January 1, 1992.

15. CONTRACTS:

To begin service under Schedule E-20, the customer may be required to sign a three-year contract. Once the three-year contract term is over, the contract will automatically continue in effect for successive terms of one year each until it is cancelled. The customer or PG&E may cancel a contract at the end of a term by giving written notice at least 30 days before the end of the term. The three-year contract will be cancelled automatically if sustained low maximum demand (below 1,000 kw -- see "Applicability") requires that the account be transferred to a different rate schedule.

Customers requesting to take curtailable service will be required to sign a supplemental agreement. This agreement will require customers to give PG&E three years notice if they desire to switch from curtailable to firm service.

PG&E shall have the right to cancel contracts for curtailable service if customers cease to be able to provide the demand reduction required for these types of service.

APPENDIX I
PACIFIC GAS AND ELECTRIC
ADOPTED STANDBY RATES

Rates:

(per kw)	
Standby Charge	$3.30
(at Secondary Distribution Voltages)	
Primry Voltage Discount	$0.70
Transmsn Voltg Discount	$2.60
(per kwh)	
On-Peak Rate Limit @ S	$1.03270
On-Peak Rate Limit @ P	$1.02745
On-Peak Rate Limit @ T	$0.82708

Schedule Changes:

1. REDUCED CUSTOMER CHARGE:

Standby customers who take service under Schedules A-1, A-10, A-11, E-19 or E-20 Transmission may qualify for a reduced customer charge. The following monthly customer charges apply to customers who own or pay special facilities charges pursuant to Rule 21 for all of the interconnection facilities in place for PG&E to provide service to them:

A-1	$2.90
A-10/A-11	$24.00
E-19T/E-20T	$392.00

2. EXPERIMENTAL ALLOWANCE FOR UNCONVENTIONAL GENERATION:

Prior to January 1, 1990, Schedule S provided for an exclusion of standby charges of up to 300 kw for customers using unconventional generation (i.e., solar heat, geothermal, etc.). This provision is eliminated pursuant to this decision. However, customers receiving the experimental allowance for unconventional generation prior to January 1, 1990 will be permitted to continue to receive an exemption of up to 300 kw until January 1, 1995.

3. REGULAR SERVICE MAXIMUM DEMAND REDUCED BY STANDBY DEMAND:

The maximum demand used to determine the regular service charges for any month will be reduced by the customer's standby demand on the utility in that month.

APPENDIX I
PAGE 21
PACIFIC GAS & ELECTRIC COMPANY
EFFECTIVE 01-01-90

Rate Component	ADOPTED RATES SUMMER	WINTER
	($/KWH, $/KW, $/CUSTOMER MONTH)	
A-RTP		
RTP Base Rate	$0.00288	$0.00288
On-Peak RTP Multiplier	3.0247	
Ptl-Peak RTP Multiplier	1.9466	1.9466
Off-Peak RTP Multiplier	1.4792	1.4792
Max. Demand (@ Primary)	$2.60	$2.60
Max. Demand (@ Secndry)	$3.30	$3.30
Customr Chg (@ Primary)	$410.00	$410.00
Customr Chg (@ Secndry)	$520.00	$520.00

Schedule change for A-RTP: The otherwise applicable bill will now depend on whether the customer would be on E-19 or E-20.

APPENDIX I
PACIFIC GAS AND ELECTRIC COMPANY
EFFECTIVE 01-01-90

SCHEDULE E-26--RESTRICTED CURTAILABLE VARIABLE-PEAK-PERIOD TIME-OF-USE SERVICE

1. APPLICABILITY:

This is an optional non-firm schedule for customers whose service otherwise qualifies for Schedules E-19 or E-20, or who are agricultural customers. Customers whose service qualifies for E-19 or E-20 are subject to the further limitation that their Standard Industrial Classification (SIC) code is 4941 (water supply) or 4952 (sewage system).

Definition of Maximum Demand: Demand will be averaged over 30-minute intervals. "Maximum demand" will be the highest of all the 30-minute averages for the billing month. If the customer's use of electricity is intermittent or subject to violent fluctuations, a 5-minute or 15-minute interval may be used instead of the 30-minute interval. If the customer has any welding machines, the customer's diversified resistance welder load, calculated in accordance with Section J of Rule 2, will be considered its maximum demand if it exceeds the maximum demand that results from averaging the customer's demand over 30-minute intervals. The customer's maximum-peak-period demand will be the highest of all the 30-minute averages for the peak period during the billing month. (See Section 5 for a definition of "Peak-Period.")

Transfers off Schedule E-26: If the customer's maximum demand drops below 500 kw and remains there for 12 consecutive months or if the customer consistently fails to meet the curtialment requirements discussed in Section 11 of this rate schedule, PG&E may at its option transfer the customer's account from Schedule E-26 to a different applicable rate schedule (excluding Schedules E-19 and E-20).

2. TERRITORY:

Schedule E-26 applies everywhere PG&E provides electricity service.

3. RATES:

Service Voltage:	Secondary (E-26S)		Primary (E-26P)		Transmission (E-26T)	
Season:	Summer	Winter	Summer	Winter	Summer	Winter
Demand Charges (per kw):						
Maximum Peak-Period Demand	$4.22	--	$3.93	--	$2.84	--
Maximum Demand	$3.30	$3.30	$2.60	$2.60	$0.70	$0.70
Energy Charges (per kwh):						
Peak-Period	$0.12579	--	$0.12145	--	$0.10446	--
Partial-Peak Period	$0.06463	$0.05525	$0.06239	$0.05335	$0.05261	$0.04532
Off-Peak Period	$0.04933	$0.04785	$0.04763	$0.04620	$0.04047	$0.03925
Excess Demand Charge: (per kwh, per non-compliance event)	$6.27077	$6.27077	$6.27077	$6.27077	$4.90970	$4.90970
Customer Charge: (per meter per month)	$330.00	$330.00	$220.00	$220.00	$510.00	$510.00

APPENDIX I
PACIFIC GAS AND ELECTRIC COMPANY
EFFECTIVE 01-01-90

SCHEDULE E-26--RESTRICTED CURTAILABLE VARIABLE-PEAK-PERIOD TIME-OF-USE SERVICE

(Continued)

3. RATES: (Cont'd.)

a. TYPES OF CHARGES: The customer's monthly charge for service under Schedule E-26 is the sum of a customer charge, demand charges, energy charges, and excess demand charges:

- The customer charge is a flat monthly fee.

- Schedule E-26 has two demand charges, a maximum-peak-period-demand charge and a maximum-demand charge. The maximum-peak-period-demand charge per kilowatt applies to the maximum demand during the month's peak hours, and the maximum-demand charge per kilowatt applies to the maximum demand at any time during the month. The bill will include both of these demand charges. (Time periods are defined in Section 5.)

- The energy charge is the sum of the energy charges from the peak, partial-peak, and off-peak periods. The customer pays for energy by the kilowatt-hour (kwh), and rates are differentiated according to time of day and time of year.

- The excess demand charge is only applicable to customers who fail to comply with the curtailment provisions of this rate schedule. The computation of this charge is discussed in Section 11 of this rate schedule.

- The monthly charges may be increased or decreased based upon the power factor. (See Section 6.)

- As shown on the rate chart, which set of customer, demand, and energy charges is paid depends on the voltage at which service is taken. Service voltages are defined in Section 4 below.

4. DEFINITION OF SERVICE VOLTAGE:

The following defines the 3 voltage classes of Schedule E-26 rates. Standard Service Voltages are listed in Rule 2.

a. Secondary: This is the voltage class if the service voltage is less than 2,000 volts or if the definitions of "primary" and "transmission" do not apply to the service.

b. Primary: This is the voltage class if the customer is served at a standard service voltage between 2,000 and 50,000 volts, and there is only one stage of transformation between the service voltage and PG&E's transmission voltage (50,000 volts or greater).

c. Transmission: This is the voltage class if the customer is served at a standard service voltage greater than 50,000 volts.

APPENDIX I
PACIFIC GAS AND ELECTRIC COMPANY
EFFECTIVE 01-01-90

SCHEDULE E-26--RESTRICTED CURTAILABLE VARIABLE-PEAK-PERIOD TIME-OF-USE SERVICE

(Continued)

5. TIME PERIODS:

Seasons of the year and times of the day are defined as follows:

SUMMER: Service from May 1 through October 31.

*Peak:			
	Group I	2:00 p.m. to 5:00 p.m.	Monday through Friday**
	Group II	3:00 p.m. to 6:00 p.m.	Monday through Friday**
Partial-Peak			
	Group I	8:30 a.m. to 2:00 p.m. and 5:00 p.m. to 9:30 p.m.	Monday through Friday
	Group II	8:30 a.m. to 3:00 p.m. and 6:00 p.m. to 9:30 p.m.	Monday through Friday
Off-Peak:		All other hours	Monday through Friday
		All day	Saturday, Sunday, holidays

WINTER: Service from November 1 through April 30.

Partial-Peak:	8:30 a.m. to 9:30 p.m.	Monday through Friday
Off-Peak:	All other hours	Monday through Friday
	All day	Saturday, Sunday, holidays

HOLIDAYS: "Holidays" for the purposes of this rate schedule are New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. The dates will be those on which the holidays are legally observed.

CHANGE FROM SUMMER TO WINTER OR WINTER TO SUMMER: When a billing month includes both summer and winter days, PG&E will calculate demand charges as follows. It will consider the applicable maximum demands for the summer and winter portions of the billing month separately, calculate a demand charge for each, and then apply the two according to the number of billing days each represents. NOTE: if your meter is read within one work day of the season changeover date (May 1 or November 1), PG&E will use only the rates and charges from the season having the greater number of days in your billing month. Work days are Monday through Friday, inclusive.

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*Providing space is available, you may have the option of choosing the applicable peak-period hours.
**Except holidays.

APPENDIX I
PACIFIC GAS AND ELECTRIC COMPANY
EFFECTIVE 01-01-90

SCHEDULE E-26--RESTRICTED CURTAILABLE VARIABLE-PEAK-PERIOD TIME-OF-USE SERVICE

(Continued)

6. POWER FACTOR ADJUSTMENTS:

The bill will be adjusted based upon the power factor. The power factor is computed from the ratio of lagging reactive kilovolt-ampere-hours to the kilowatt-hours consumed in the month. Power factors are rounded to the nearest whole percent.

The rates in this rate schedule are based on a power factor of 85 percent. If the average power factor is greater than 85 percent, the total monthly bill (excluding any taxes) will be reduced by 0.06 percent for each percentage point above 85 percent. If the average power factor is below 85 percent, the total monthly bill (excluding any taxes) will be increased by 0.06 percent for each percentage point below 85 percent.

7. CHARGES FOR TRANSFORMER LOSSES:

If the electricity used undergoes transformation between PG&E's delivery point and the metering point, the demand and energy meter readings used in determining the charges will be increased to correct for transformer losses. A two percent addition will be made for each stage of transformation between PG&E's delivery and metering points.

8. STANDARD SERVICE FACILITIES:

If PG&E must install any new or additional facilities to provide the customer with service under Schedule E-26, the customer may have to pay some of the cost. Any advance necessary and any monthly charge for the facilities will be specified in a facilities charge agreement. See Rules 2, 15, and 16 and the facilities charge agreement form (Form No. 79-245) for details.

Facilities installed to serve the customer may be removed when service is discontinued. The customer will then have to repay PG&E for all or some of its investment in the facilities. Terms and conditions for repayment will be set forth in the facilities charge agreement.

9. SPECIAL FACILITIES:

PG&E will normally install only those standard facilities it deems necessary to provide service under Schedule E-26. If the customer requests any additional facilities, those facilities will be treated as "special facilities" in accordance with Section I of Rule 2.

10. ARRANGEMENTS FOR VISUAL-DISPLAY METERING:

If the customer wishes to have visual-display metering equipment in addition to the regular metering equipment, the customer must submit a written request to PG&E. PG&E will provide and install the equipment within 180 days of receiving the request. The visual-display metering equipment will be installed near the present metering equipment. The customer will be responsible for providing the required space and associated wiring.

PG&E will continue to use the regular metering equipment for billing purposes.

11. CURTAILMENTS:

a. EMERGENCY CURTAILMENT REQUIREMENT: If a customer takes service under Schedule E-26 its entire electric load is nonfirm and, therefore, subject to curtailment. PG&E will make requests for such curtailments from its nonfirm service customers when, in PG&E's sole judgement, a systemwide or local operating condition exists which will impair the ability of PG&E to meet the demands of its other customers.

b. LIMIT ON EMERGENCY CURTAILMENT: Customers are limited to two six-hour curtailments per year, and must be given at least six hour's notice prior to a curtailment of this length. Curtailments of up to three hours are unlimited, but the customer must be given at least one hour's notice prior to curtailment.

APPENDIX I
PACIFIC GAS AND ELECTRIC COMPANY
EFFECTIVE 01-01-90

SCHEDULE E-26--RESTRICTED CURTAILABLE VARIABLE-PEAK-PERIOD TIME-OF-USE SERVICE

(Continued)

11. CURTAILMENTS: (Cont'd.)

c. EMERGENCY CURTAILMENT PROCEDURE: When it becomes necessary for PG&E to request a curtailment, PG&E will notify the customer by telephone or electronic mail. This notification will designate a time by which the customers demand must be reduced to a specified number of kilowatts.

The customer may not resume the use of curtailed power until notified by PG&E that it may do so or until the customer has curtailed its service for six hours.

d. EXCESS DEMAND CHARGES: If PG&E requests that a customer curtail the use of electricity and the customer fails to do so by the time specified, the customer must pay an excess demand charge. This charge will be payable in addition to the regular charges.

The excess demand to which this charge is applied will be calculated by determining the total amount of excess energy taken during the curtailment period (the difference between the customer's load during the curtailment period and the amount PG&E requested to be curtailed) and multiplying this total times the excess demand charge (per kwh).

The applicable excess demand charges, which vary by service voltage level, are listed in Section 3 of this schedule.

e. EMERGENCY-NOTICE PROVISION: If there is an emergency on the PG&E system, PG&E may ask the customer to curtail the use of electricity on less notice than is usually allowed under the curtailment limitations. The customer will be asked to make the best effort to comply. The customer will not be assessed the noncompliance penalty for failing to comply within the shorter notice period, but customer will be assessed this penalty if the regular notice period for the option passes and the customer still has not curtailed use.

f. TELEPHONE LINE REQUIREMENTS: Non-firm customers are required to make available a telephone line and space for a notification printer. This requirement is in addition to any other equipment requirement which may apply.

12. CONTRACTS:

Schedule E-26 is an experimental rate, the future availability of which is subject to review. To begin service under Schedule E-26, the customer must sign a contract with an initial expiration date of December 31, 1992. At least 30 days prior to this expiration date, PG&E will inform the customer if the rate will not be extended. If it is extended, the contract will automatically continue in effect for successive terms of one year each until it is cancelled. The customer or PG&E may cancel a contract at the end of a term by giving written notice at least 30 days before the end of the term. The contract will be cancelled automatically if sustained low maximum demand (below 500 kw -- see "Applicability") requires that the customer's account be transferred to a different rate schedule.

APPENDIX I
PAGE 27
ADOPTED LARGE POWER RATES

Schedule ED--Economic Development Rate

APPLICABILITY:
This voluntary schedule is available on an experimental basis to qualified customers locating in or expanding in Enterprise Zones designated by the State of California under the 1984 Enterprise Zone Act. This schedule will expire December 31, 1994.

TERRITORY:
Enterprise Zones designated by the State of California under the provisions of the 1984 Enterprise Zone Act currently include areas located in Southeast Bakersfield, Eureka, Southwest Fresno, Madera, Pittsburg, West Sacramento, East San Jose and Yuba-Sutter.

RATES:
A three year declining rate discount (excluding local taxes) based on the energy, demand and customer charge portion of the E-19 or E-20 rate schedule which would otherwise apply. The discount applies only to the firm service portion of the bill.

Discount

First twelve months	....	15%
Second twelve months	....	10%
Third twelve months	....	5%

Discount Limiter--The average discounted rate that results under this Schedule each month cannot be less than PG&E's marginal cost of service for the same month. The California Public Utilities Commission's most recently adopted marginal costs will be used for this calculation.

SPECIAL CONDITIONS:

1. Qualified customers: Qualified customers are industrial customers with new or additional firm service billing demand of at least 500 kW. New or additional billing demand does not include billing demand that already exists within the state of California. Industrial customers are defined as customers engaged in in businesses classified under the Federal Standard Industrial Classification (SIC), secondary codes 2011 through 3999, inclusive, or any other customers eligible for service under Schedules E-19 or E-20 that at the utility's sole discretion may be determined to qualify for this schedule. Residential and commercial customers customers and governmental agencies are not qualified customers under this rate schedule.

2. Limitations: Application of this Schedule will be limited to either a maximum of eight qualified participants or a combined net load addition for all participants of 20 mW, whichever comes first. No discount will be paid beyond December 31, 1994.

3. Contract: Service under this Schedule is provided under a three year contract.

4. Start date: The start date of the discount rate period shall commence within 24 months from the date of execution of the contract for service and shall be designated by customer within the contract.

5. Metering: Separate electric metering for new or additional load may be required if, in the utility's sole opinion, it is necessary to provide service under this Schedule. The customer will be responsible for any costs associated with providing separate electric metering.

6. Transfers off of Schedule E-19 and E-20: If the customer's maximum demand drops and is determined by PG&E to be ineligible for both Schedule E-19 and E-20, no discount will be paid for periods of ineligibility.

7. Limitation of rate limiters: Average and peak period rate limiters may apply to your bill under Schedule E-19 or E-20. The level of rate limiters will not be reduced by this Schedule.

8. Conservation: In order to be eligible for this Schedule, customers must allow PG&E to conduct a site inspection for the purpose of making conservation options available to customers. PG&E will advise all new customers of a range of cost-effective conservation options on a site-specific basis.

APPENDIX I
PAGE 28
PACIFIC GAS & ELECTRIC COMPANY
EFFECTIVE 01-01-90

Rate Component	ADOPTED RATES SUMMER	WINTER
	($/KWH, $/KW, $/CUSTOMER MONTH)	
AGRICULTURAL /a/		
AG-1-A		
Energy Charge	$0.11441	$0.11441
Demand Charge	$1.80	$1.80
Customer Charge	$10.00	$10.00
AG-1-B		
Energy Charge	$0.10161	$0.10161
Demand Charge	$2.20	$1.50
Customer Charge	$10.00	$10.00
AG-R-A		
On-Peak Energy	$0.27632	
Partial-Peak Energy		$0.05789
Off-Peak Energy	$0.06444	$0.04604
Demand Charge	$1.80	$1.80
Customer Charge	$10.00	$10.00
Meter Charge	$6.20	$6.20
AG-R-B		
On-Peak Energy	$0.24105	
On-Peak Demand	$2.20	
Partial-Peak Energy		$0.06613
Off-Peak Energy	$0.07139	$0.05259
Maximum Demand	$2.20	$1.50
Customer Charge	$10.00	$10.00
Meter Charge	$5.10	$5.10
AG-V-A		
On-Peak Energy	$0.27273	
Partial-Peak Energy		$0.05714
Off-Peak Energy	$0.06219	$0.04544
Demand Charge	$1.80	$1.80
Customer Charge	$10.00	$10.00
Meter Charge	$6.20	$6.20

/a/ The average rate limiter applicable to the "AG" series will be $.97337/kWh. This amount equals the existing rate limiter ($.82200/kWh) times the cap computed for agricultural intra-class revenue allocation, plus five percent (a total increase of 18.42)%).

APPENDIX I
PAGE 29
PACIFIC GAS & ELECTRIC COMPANY
EFFECTIVE 01-01-90

Rate Component	ADOPTED RATES SUMMER	WINTER
	($/KWH, $/KW, $/CUSTOMER MONTH)	
AG-V-B		
On-Peak Energy	$0.21405	
On-Peak Demand	$2.20	
Partial-Peak Energy		$0.06413
Off-Peak Energy	$0.06710	$0.05099
Maximum Demand	$2.20	$1.50
Customer Charge	$10.00	$10.00
Meter Charge	$5.10	$5.10
AG-4-A		
On-Peak Energy	$0.26992	
Partial-Peak Energy		$0.05655
Off-Peak Energy	$0.05429	$0.04497
Demand Charge	$1.80	$1.80
Customer Charge	$10.00	$10.00
Meter Charge	$6.20	$6.20
AG-4-B		
On-Peak Energy	$0.18083	
On-Peak Demand	$2.20	
Partial-Peak Energy		$0.05920
Off-Peak Energy	$0.05625	$0.04707
Maximum Demand	$2.20	$1.50
Customer Charge	$10.00	$10.00
Meter Charge	$5.10	$5.10
AG-4-C		
On-Peak Energy	$0.18083	
On-Peak Demand	$2.20	
Partial-Peak Energy	$0.07679	$0.05920
Off-Peak Energy	$0.04975	$0.04707
Maximum Demand	$2.20	$1.50
Customer Charge	$10.00	$10.00
Meter Charge	$5.10	$5.10

APPENDIX I
PAGE 30
PACIFIC GAS & ELECTRIC COMPANY
EFFECTIVE 01-01-90

Rate Component	ADOPTED RATES SUMMER	WINTER
	($/KWH, $/KW, $/CUSTOMER MONTH)	
AG-5-A		
On-Peak Energy	$0.19119	
Partial-Peak Energy		$0.04006
Off-Peak Energy	$0.03933	$0.03185
Demand Charge	$4.55	$4.55
Customer Charge	$10.00	$10.00
Meter Charge	$6.20	$6.20
AG-5-B		
On-Peak Energy	$0.12313	
On-Peak Demand	$2.25	
Partial-Peak Energy		$0.03668
Off-Peak Energy	$0.03539	$0.02917
Maximum Demand	$5.45	$3.65
Customer Charge	$10.00	$10.00
Meter Charge	$5.10	$5.10
AG-5-C		
On-Peak Energy	$0.12313	
On-Peak Demand	$2.25	
Partial-Peak Energy	$0.04846	$0.03668
Off-Peak Energy	$0.03082	$0.02917
Maximum Demand	$5.45	$3.65
Customer Charge	$10.00	$10.00
Meter Charge	$5.10	$5.10
AG-6-B		
Energy Charge	$0.05976	$0.03200
Demand Charge	$5.45	$3.65
Customer Charge	$10.00	$10.00

APPENDIX I
PACIFIC GAS AND ELECTRIC COMPANY
EFFECTIVE 01-01-90

Schedule changes to interruptible service for all AG schedules: The following passage will be added as Section 12 of Schedules AG-1 and AG-6, and as Section 14 of Schedules AG-4, AG-5, AG-V, and AG-R.

AG-INTERRUPTIBLE SERVICE

The customer may be eligible, at PG&E's discretion, to participate in the company's experimental agricultural interruptible program. If the customer participates, it will receive credits for allowing PG&E to interrupt service. Interruptions are signaled by PG&E through a remote-controlled switch installed on the customer's pump. The provisions of these conditions are available under one of the following three options:

	Maximum Number of Consecutive Interruptions	Maximum Number of Interruptions	Maximum Interruption Length	PER-SIGNAL CREDIT (per kw of Interruptible Load)
Option A	2 days	2 per week, 20 per year	4 hours	$1.86 per signal
Option B	1 day	2 per week, 20 per year	4 hours	$1.49 per signal
Option C	2 days	2 per week, 20 per year	6 hours	$2.47 per signal

The customer's interruptible load (measured in kw) will be determined by PG&E based upon either the customer's billing demand (measured by PG&E's demand meter) or the nameplate rating of the customer's pump. If billing demand or nameplate rating is not available, or if more than one discrete load is served through the customer's account, PG&E will use test data (or other available data) to determine interruptible load. Interruptions of service are limited to weekdays between the hours of 10:00 a.m. and 8:00 p.m. during the summer season.

For making its pump available for interruption, the customer will receive a per-signal credit each time PG&E interrupts the pump by signaling the remote-controlled switch.

The per-signal credit, less any penalty for noncompliance, will be applied in full to the customer's regular bill provided that the average rate paid is not less than that Energy Cost Adjustment Clause shown in the Rate Summary section of the Preliminary Statement.

The customer will be provided with the means to override remote-controlled interruptions to service. If the customer chooses to operate its pump during an interruption period the customer will be required to pay a penalty for the electricity used in the interruption period(s). This penalty is in addition to regularly applicable charges. Penalty charges are as follows:

	Penalty per kwh
Option A	$0.47
Option B	0.37
Option C	0.62

If the customer does not use the override feature during the course of a calendar year, it earns an end-of-year bonus. The bonus shall be 40 percent of the total per-signal credits earned in the year.

During emergency periods on PG&E's system, the customer's pump may be interrupted in a manner not consistent with the conditions described above. Such an emergency could be caused by the failure of PG&E's generation or transmission equipment, effects of severe weather conditions, PG&E's requirement to keep contractual supply agreements with other utilities, or requirements of regulatory agencies. The customer will be asked to make its best effort to accomplish PG&E's request for interruptions, but will not be penalized for non-compliance when PG&E interrupts service for such system emergencies in a manner inconsistent with the conditions of this program (described above). However, if emergency interruptions are made consistent with the applicable conditions of this program, the customer will be liable for the noncompliance penalty described in this section.

APPENDIX I

PACIFIC GAS AND ELECTRIC COMPANY
RATES FOR SCHEDULES LS-1, LS-2 AND OL-1
12 MONTHS BEGINNING JANUARY 1, 1990

--NOMINAL LAMP RATINGS--			ALL NIGHT RATES PER LAMP PER MONTH													HALF-HOUR ADJ (LS-1, LS-2 & OL-1)
			SCHEDULE LS-2			SCHEDULE LS-1										
LAMP WATTS	KWHR PER MONTH	AVERAGE INITIAL LUMENS	A	B	C	A	B	C	D	D.1	E	E.1	F	F.1	OL-1	
MERCURY VAPOR LAMPS																
100	40	3,500	3.109	3.854	4.324	8.174	--	6.671	--	--	--	--	--	--	--	.134
175	68	7,500	5.180	5.906	6.241	9.991	8.064	8.620	--	--	13.514	13.514	15.892	13.228	9.991	.229
250	97	11,000	7.325	8.079	8.514	12.682	10.562	--	--	--	--	--	--	--	--	.326
400	152	21,000	11.393	12.137	12.559	16.996	14.633	--	--	--	--	--	--	--	16.996	.511
700	266	37,000	19.824	20.691	21.426	26.005	23.655	--	--	--	--	--	--	--	--	.894
1,000	377	57,000	28.034	28.872	29.474	--	--	--	--	--	--	--	--	--	--	1.267
INCANDESCENT LAMPS																
58	20	600	--	--	--	10.071	--	--	--	--	--	--	--	--	--	.067
92	31	1,000	2.444	4.759	5.545	10.884	--	--	--	--	--	--	--	--	--	.104
189	65	2,500	4.958	7.203	8.244	13.600	9.906	--	--	--	--	--	--	--	--	.219
295	101	4,000	7.621	9.751	10.976	16.337	12.644	--	--	--	--	--	--	--	--	.340
405	139	6,000	10.431	12.618	13.549	19.551	--	--	--	--	--	--	--	--	--	.467
620	212	10,000	15.831	18.003	18.705	--	--	--	--	--	--	--	--	--	--	.713
860	294	15,000	21.895	24.186	--	--	--	--	--	--	--	--	--	--	--	.988
LOW PRESSURE SODIUM VAPOR LAMPS																
35	21	4,800	1.704	--	--	--	--	--	--	--	--	--	--	--	--	.071
55	29	8,000	2.296	--	--	--	--	--	--	--	--	--	--	--	--	.097
90	45	13,500	3.479	--	--	--	--	--	--	--	--	--	--	--	--	.151
135	62	21,500	4.737	--	--	--	--	--	--	--	--	--	--	--	--	.208
180	78	33,000	5.920	--	--	--	--	--	--	--	--	--	--	--	--	.262
HIGH PRESSURE SODIUM VAPOR LAMPS																
AT 120 VOLTS																
70	29	5,800	2.296	3.107	3.609	6.811	--	5.585	10.101	8.426	10.143	8.440	10.803	9.481	6.811	.097
100	41	9,500	3.183	4.091	4.486	7.815	--	6.587	11.074	9.608	11.076	9.608	11.945	10.704	7.815	.138
150	60	16,000	4.589	5.496	5.891	9.409	--	8.110	12.398	11.036	12.516	11.076	13.619	12.267	--	.202
AT 240 VOLTS																
70	34	5,800	2.666	3.477	3.972	--	--	--	--	--	--	--	--	--	--	.114
100	47	9,500	3.627	4.535	4.971	--	--	--	--	--	--	--	--	--	--	.158
150	69	16,000	5.254	6.162	6.556	--	--	--	--	--	--	--	--	--	--	.232
200	81	22,000	6.142	7.069	7.710	11.980	--	10.304	--	--	14.736	13.929	17.374	15.320	11.980	.272
250	100	27,000	7.547	8.474	9.116	14.488	--	11.834	--	--	16.439	15.366	19.243	17.523		.336
310	119	37,000	8.952	--	--	--	--	--	--	--	--	--	--	--	--	.400
400	154	46,000	11.541	12.448	13.109	19.378	--	16.051	--	--	20.731	20.485	24.036	22.016	--	.518
METAL HALIDE LAMPS																
400	162	30,000	12.133	--	--	--	--	--	--	--	--	--	--	--	--	.545
1,000	387	90,000	28.774	--	--	--	--	--	--	--	--	--	--	--	--	1.301

12/18/1989

APPENDIX I
PACIFIC GAS AND ELECTRIC
ADOPTED STREET LIGHT RATES
PAGE 33

Schedule LS-3

Service charge ($/meter/month)	$3.00
Switching charge ($ per circuit)	$3.25
Energy charge ($ per kWh)	$0.07396

(END APPENDIX I)

APPENDIX J
PAGE 1
PACIFIC GAS AND ELECTRIC COMPANY
RATES FOR SCHEDULES LS-1, LS-2 AND OL-1
12 MONTHS BEGINNING JANUARY 1, 1991
(Facility and Maintenance Rates Only)

--NOMINAL LAMP RATINGS--			ALL NIGHT RATES PER LAMP PER MONTH													
			SCHEDULE LS-2			SCHEDULE LS-1										HALF-HOUR ADJ. (LS-1 (LS-2 & OL-1)
LAMP WATTS	KWHR PER MONTH	AVERAGE INITIAL LUMENS	A	B	C	A	B	C	D	D.1	E	E.1	F	F.1	OL-1	
MERCURY VAPOR LAMPS																
100	40	3,500	--	.971	1.458	5.933	--	4.131	--	--	--	--	--	--	--	.000
175	68	7,500	--	.933	1.353	5.527	--	4.105	--	--	--	--	12.298	10.166	5.527	.000
250	97	11,000	--	.990	1.459	6.339	--	--	--	--	--	--	--	--	--	.000
400	152	21,000	--	.971	1.424	6.545	--	--	--	--	--	--	--	--	6.545	.000
700	266	37,000	--	1.215	1.835	7.122	--	--	--	--	--	--	--	--	--	.000
1,000	377	57,000	--	1.159	1.712	--	--	--	--	--	--	--	--	--	--	.000
INCANDESCENT LAMPS																
58	20	600	--	--	--	8.591	--	--	--	--	--	--	--	--	--	.000
92	31	1,000	--	2.607	3.252	8.591	--	--	--	--	--	--	--	--	--	.000
189	65	2,500	--	2.664	3.437	8.792	--	--	--	--	--	--	--	--	--	.000
295	101	4,000	--	2.641	3.506	8.867	--	--	--	--	--	--	--	--	--	.000
405	139	6,000	--	2.855	3.572	9.271	--	--	--	--	--	--	--	--	--	.000
620	212	10,000	--	2.828	3.431	--	--	--	--	--	--	--	--	--	--	.000
860	294	15,000	--	3.063	--	--	--	--	--	--	--	--	--	--	--	.000
LOW PRESSURE SODIUM VAPOR LAMPS																
35	21	4,800	--	--	--	--	--	--	--	--	--	--	--	--	--	.000
55	29	8,000	--	--	--	--	--	--	--	--	--	--	--	--	--	.000
90	45	13,500	--	--	--	--	--	--	--	--	--	--	--	--	--	.000
135	62	21,500	--	--	--	--	--	--	--	--	--	--	--	--	--	.000
180	78	33,000	--	--	--	--	--	--	--	--	--	--	--	--	--	.000
HIGH PRESSURE SODIUM VAPOR LAMPS																
AT 120 VOLTS																
70	29	5,800	--	1.075	1.578	5.257	--	3.888	--	7.119	--	7.146	10.287	9.229	5.257	.000
100	41	9,500	--	1.137	1.586	5.322	--	3.989	--	7.309	--	7.309	10.494	9.501	5.322	.000
150	60	16,000	--	1.137	1.586	5.642	--	4.090	--	7.279	--	7.358	10.823	9.741	--	.000
AT 240 VOLTS																
70	34	5,800	--	1.075	1.574	--	--	--	--	--	--	--	--	--	--	.000
100	47	9,500	--	1.137	1.607	--	--	--	--	--	--	--	--	--	--	.000
150	69	16,000	--	1.137	1.586	--	--	--	--	--	--	--	--	--	--	.000
200	81	22,000	--	1.147	1.720	6.870	--	4.736	--	--	--	8.342	12.767	11.123	6.870	.000
250	100	27,000	--	1.147	1.720	7.298	--	4.896	--	--	--	8.506	13.197	11.822		.000
310	119	37,000	--	--	--	--	--	--	--	--	--	--	--	--	--	.000
400	154	46,000	--	1.137	1.720	8.264	--	5.134	--	--	--	9.218	13.896	12.280	--	.000
METAL HALIDE LAMPS																
400	162	30,000	--	--	--	--	--	--	--	--	--	--	--	--	--	.000
1,000	387	90,000	--	--	--	--	--	--	--	--	--	--	--	--	--	.000

12/18/1989

APPENDIX J
PAGE 2
PACIFIC GAS AND ELECTRIC COMPANY
RATES FOR SCHEDULES LS-1, LS-2 AND OL-1
12 MONTHS BEGINNING JANUARY 1, 1992
(Facility and Maintenance Rates Only)

--NOMINAL LAMP RATINGS--			ALL NIGHT RATES PER LAMP PER MONTH														
			SCHEDULE LS-2			SCHEDULE LS-1											HALF-HOUR ADJ. (LS-1 (LS-2 & OL-1)
LAMP WATTS	KWHR PER MONTH	AVERAGE INITIAL LUMENS	A	B	C	A	B	C	D	D.1	E	E.1	F	F.1	OL-1	
MERCURY VAPOR LAMPS																
100	40	3,500	--	1.047	1.551	6.651	--	4.548	--	--	--	--	--	--	--	.000
175	68	7,500	--	.990	1.494	6.093	--	4.621	--	--	--	--	13.733	12.135	6.093	.000
250	97	11,000	--	1.075	1.579	7.170	--	--	--	--	--	--	--	--	--	.000
400	152	21,000	--	1.047	1.551	7.335	--	--	--	--	--	--	--	--	7.335	.000
700	266	37,000	--	1.413	1.917	7.912	--	--	--	--	--	--	--	--	--	.000
1,000	377	57,000	--	1.329	1.833	--	--	--	--	--	--	--	--	--	--	.000
INCANDESCENT LAMPS																
58	20	600	--	--	--	8.591	--	--	--	--	--	--	--	--	--	.000
92	31	1,000	--	2.748	3.252	8.591	--	--	--	--	--	--	--	--	--	.000
189	65	2,500	--	2.932	3.437	[illegible]	--	--	--	--	--	--	--	--	--	.000
295	101	4,000	--	3.002	3.506	8.867	--	--	--	--	--	--	--	--	--	.000
405	139	6,000	--	3.372	3.876	9.271	--	--	--	--	--	--	--	--	--	.000
620	212	10,000	--	3.332	3.836	--	--	--	--	--	--	--	--	--	--	.000
860	294	15,000	--	3.685	--	--	--	--	--	--	--	--	--	--	--	.000
LOW PRESSURE SODIUM VAPOR LAMPS																
35	21	4,800	--	--	--	--	--	--	--	--	--	--	--	--	--	.000
55	29	8,000	--	--	--	--	--	--	--	--	--	--	--	--	--	.000
90	45	13,500	--	--	--	--	--	--	--	--	--	--	--	--	--	.000
135	62	21,500	--	--	--	--	--	--	--	--	--	--	--	--	--	.000
180	78	33,000	--	--	--	--	--	--	--	--	--	--	--	--	--	.000
HIGH PRESSURE SODIUM VAPOR LAMPS																
AT 120 VOLTS																
70	29	5,800	--	1.187	1.692	5.848	--	4.336	--	7.956	--	7.998	11.915	11.122	5.848	.000
100	41	9,500	--	1.215	1.720	5.861	--	4.423	--	8.042	--	8.043	12.075	11.330	5.861	.000
150	60	16,000	--	1.215	1.720	6.312	--	4.507	--	7.960	--	8.078	12.464	11.653	--	.000
AT 240 VOLTS																
70	34	5,800	--	1.187	1.692	--	--	--	--	--	--	--	--	--	--	.000
100	47	9,500	--	1.215	1.720	--	--	--	--	--	--	--	--	--	--	.000
150	69	16,000	--	1.215	1.720	--	--	--	--	--	--	--	--	--	--	.000
200	81	22,000	--	1.215	1.720	7.750	--	5.158	--	--	--	8.745	14.150	12.917	7.750	.000
250	100	27,000	--	1.215	1.720	7.505	--	5.353	--	--	--	9.043	14.548	13.516		.000
310	119	37,000	--	--	--	--	--	--	--	--	--	--	--	--	--	.000
400	154	46,000	--	1.215	1.720	8.540	--	5.606	--	--	--	9.341	15.146	13.934	--	.000
METAL HALIDE LAMPS																
400	162	30,000	--	--	--	--	--	--	--	--	--	--	--	--	--	.000
1,000	387	90,000	--	--	--	--	--	--	--	--	--	--	--	--	--	.000

(END OF APPENDIX J)

APPENDIX K
Page 1

List of Abbreviations

A.	- Application
A&G	- Administrative and General
ACAP	- Annual Cost Allocation Proceeding
ACWA	- Association of California Water Agencies
AGA	- American Gas Association
ALJ	- Administrative Law Judge
Anchor	- Anchor Glass Container and Energy System Engineers, Inc.
BART	- Bay Area Rapid Transit District
BRPU	- Biennial Resource Plan Update
Btu	- British Thermal Unit
CACD	- Commission Advisory and Compliance Division
Cal-Neva	- California-Nevada Community Action Association
Cal-SLA	- California City-County Street Light Association
Caltrans	- California Transportation
CCFT	- California Corporate Franchise Tax
CEC	- California Energy Commission
CPUC	- California Public Utilities Commission
CFBF	- California Farm Bureau Federation
CFM	- Common Forecasting Methodology
CIEE	- California Institute for Energy Efficiency
CIS	- Case Information System
CLECA	- California Large Energy Consumers Association

APPENDIX K
Page 2

CMA	- California Manufacturers Association
COMPRESS	- Computer-Produced Estimating System
Contra Costa	- Contra Costa County
COTP	- California-Oregon Transmission Project
CSB	- Cogeneration Service Bureau
CTPA	- California Travel Parks Association
D.	- Decision
DGS	- California Department of General Services
DH&S	- Deloitte, Haskins and Sells
DRA	- Division of Ratepayer Advocates
DSM	- Demand-Side Management
EAD	- Expedited Application Docket
ECAC	- Energy Cost Adjustment Clause
Edison	- Southern California Edison Company
EEI	- Edison Electric Institute
ELFIN	- Production Cost Model
EPMC	- Equal Percentage of Marginal Cost
EPRI	- Electric Power Research Institute
ERA	- Energy and Resources Advocates
ERAM	- Electric Revenue Adjustment Mechanism
ERI	- Energy Reliability Index
ERTA	- Economic Recovery Tax Act of 1981
EUE	- Expected Unserved Energy
FAMIS	- Financial Management Information System

APPENDIX K
Page 3

FASB	- Financial Accounting Standards Board
FEA	- Federal Executive Agencies
FEIP	- Funding, Evaluation, and Implementation Principles
FERC	- Federal Energy Regulatory Commission
FF&U	- Franchise Fees and Uncollectibles
GO	- General Order
GPLF	- General Plant Loading Factor
GRC	- General Rate Case
GWh	- Gigawatt-Hour
HMO	- Health Maintenance Organization
HVDC	- High Voltage Direct Current
I.	- Investigation
IER	- Incremental Energy Rate
Industrial Users	- Industrial Users
kV	- Kilovolt
kWh	- Kilowatt-Hour
LADWP	- Los Angeles Department of Water and Power
League	- California League of Food Processors
LIRA	- Low-Income Ratepayer Assistance
LOLP	- Loss of Load Probability
MAAC	- Major Additions Adjustment Clause
MIP	- Management Incentive Plan
MMBtu	- Million British Thermal Units
M&S	- Materials and Services

APPENDIX K
Page 4

M&O	- Maintenance and Operation
MSI	- Materials and Service Index
MW	- Megawatt
NARUC	- National Association of Regulatory Utility Commissioners
NOI	- Notice of Intention
NOx	- Oxides of Nitrogran
OCLD-RCN	- Original Cost Less Depreciation-Replacement Cost New
O&M	- Operations and Maintenance
PG&E	- Pacific Gas & Electric Company
PHFU	- Plant Held for Future Use
PP&L	- Pacific Power and Light Company
PROMOD	- Production Simulation Model
PRP	- Pipeline Replacement Program
PSD	- Public Staff Division
PSEA	- Pacific Service Employees Association
PU	- Public Utilities
PUPC	- Power Users Protection Council
QF	- Qualifying Facility
RCN-ECC	- Replacement Cost New-Economic Carrying Charge
RD&D	- Research, Development and Demonstration
RIM	- Ratepayer Impact Measure
ROE	- Return on Equity
RV	- Recreational Vehicle

APPENDIX K
Page 5

SAPC	- System Average Percentage Change
SCC	- Tecogen, Inc., Milpitas Unified School District, and other members of the Small Cogenerators of California
SCRUB	- Schools Committee to Reduce Utility Bills
SDG&E	- San Diego Gas & Electric Company
SMUD	- Sacramento Municipal Utility District
TCAP	- Target Customer Appliance Program
TCDAP	- Target Customer Direct Assistance Program
TES	- Thermal Energy Storage
TOU	- Time of Use
TRC	- Total Resource Cost
TURN	- Toward Utility Rate Normalization
WACOG	- Weighted Average Cost of Gas
WMA	- Western Mobilehome Association
W/MBE	- Women and Minority Business Enterprises
UEG	- Utility Electric Generation
UFR	- Underfrequency Relay
Unocal	- Unocal Corporation
ZIP	- Zero-interest Load Program

(END OF APPENDIX K)

Plant Held for Future Use Guidelines

1. This appendix presents guidelines by which the reasonableness of including or maintaining items in Plant Held for Future Use (PHFU) can be judged. These guidelines are applicable to Pacific Gas and Electric Company.

2. The guidelines are as follows:

a. All items in PHFU must have a specific plan for use.

b. The need for each item must be justified before being placed in PHFU.

c. If, at any time, the needs or plans for the use of an item change so that a specific plan for use no longer exists, the item shall be removed from PHFU.

d. The maximum time period for maintaining any item in PHFU prior to its inclusion in a construction budget is shown on the following table and varies from three to 10 years depending on the type of plant.

e. If, after the allowed time period, an item has not been included in a construction budget, the item will be removed from PHFU until such time that it is included in a construction budget.

f. The maximum forecast period for a project in a construction budget will be no more than five years.

g. Therefore, the maximum time any item could be maintained in PHFU prior to the start of construction will be 8 to 15 years depending on the type of plant.

Electric and Gas Utilities

Type of Plant	Time Period
Production Plant:	
Power Plant (New)	10 years
Transmission Plant:	
Transmission Line & Substation .... (related to new Power Plant)	10 years
Transmission Line & Substation .... (not related to new Power Plant)	5 years
Distribution Plant:	
Distribution Substation	5 years
Gas Storage:	5 years
General Plant:	3 years

3. A specific plan implies that the utility knows exactly what the item is going to be used for.

4. For the purposes above, that a construction budget project should: (1) have been reviewed by the utility for need and cost; and (2) be part of the capital budget prepared by the utility annually and authorized by the utility's management.

5. There may be special cases where strict adherence to a set of guidelines such as listed above may not be appropriate. Such exceptions can be judged on their own merits on a case-by-case basis. In these cases, should the utility exceed the maximum time period for an item without inclusion in its capital budget, it must satisfactorily establish the following items in order to keep the item in PHFU:

a. There is still a definite plan and need to retain the item in PHFU;

b. Economic analysis justifies the retention; and

c. There are mitigating circumstances to require the retention.

6. It is desirable to establish criteria in order to minimize the amounts of PHFU to be included in rate base. As such, the adoption of the foregoing set of guidelines is necessary to provide utilities and ratepayers with reasonable ratemaking treatment of PHFU.

7. Nothing in this exhibit should be interpreted as precluding the ability of the ratepayers to recover gains on sales of plant that has at some time earned a return as PHFU.

(END OF APPENDIX L)

G. MITCHELL WILK, Commissioner, concurring:

The General Rate Case is an important forum for the Commission to enact policy and review the implementation of policies carried through over time. The General Rate Case can act as a gauge of our progress, and of the temper of our current times. This case reflects many of the important issues before us. I therefore take this opportunity to comment on several aspects of PG&E's rate design. Several elements of this rate design not only indicate policy directions for PG&E, but also send signals to all California utilities regarding Commission priorities.

In the area of conservation, we close the 1980s with a return to the awareness of scarce resources which marked earlier decades. We begin the 1990s with a "collaborative process" in place, which will pool our collective knowledge and creativity in designing conservation and Demand-Side Management programs. I reaffirm my earlier statement at our Demand-Side Management En Banc that energy efficiency is "back on the front burner." I strongly urge PG&E and all other California energy utilities to fully participate in this process.

PG&E's budget for research and implementation programs on both the gas and electric side renews the company's commitment to energy efficiency. This commitment clearly lagged in the 1980s. The new life in these programs reflects both economic and environmental concerns: Doing more work with less energy is the key to our State's sustained competitiveness and environmental quality.

The expansion in PG&E's efficiency programs that we approve today is just a first step. The Commission expects to see many additional initiatives from PG&E and the other regulated utilities in the months ahead. We will be satisfied with nothing less than international leadership in the delivery of cost-effective energy efficiency improvements. As California has led the country in standards for appliance efficiency, in weatherization programs, and in policies designed to protect our air, water, and wildlife, so California can be a leader in energy resource planning and conservation.

Utility efficiency depends on accurate costing and use of our resources. Consumers must get straightforward economic signals from utilities which tell them what their cost is to the system, and where the best value is for their dollars. These signals must be accurate for all classes of ratepayers, and this central policy objective is carried out in two further areas of rate design: The closing of the gap between Tier One and Tier Two rates; and the movement of different classes towards equal percentage of marginal cost (EPMC).

Senate Bill 987 required the Commission to close the gap in Tier One and Tier Two rates by January 1991. This decision follows the mandate of the Legislature by lowering the differential another 25% from current levels. I believe we have furthered the legislative course set in 1988 while also taking a middle ground between the various rate design proposals. The 25% rate shift now will prevent undue rate shock both in January 1990 and January 1991, but more must be done. The other energy utilities must follow PG&E's lead by narrowing the Tier One/Tier Two differential and getting on target for 1991.

During the next year, the Commission must determine how much farther to go in closing the Tier One/Tier Two gap. The Commission must decide what level of difference between the two rates, if any, will act as an incentive to consumers to conserve and whether this is the best way to accomplish such objectives. With the help of utilities and conservation groups, we should identify the need for and level of a target conservation premium and plan a schedule for achieving it.

While the Commission moves to realign the Tier One and Tier Two rates, we have already implemented a 15% discount for low income customers to help ease this customer class into the new rate structure, as mandated by statute. In D.89-09-044 the Commission recognized that this discount currently subsidizes low-income ratepayers to a greater extent than the old Baseline program. When the goal of the legislation is fulfilled, low-income ratepayers should be receiving the same amount of rate relief--but no more --that they formerly received through Baseline.

The Commission however, has not made as much progress in another policy area in this case: The movement of agricultural rates towards their equal percentage of marginal cost. It has long been the Commission's objective to adjust rate design to reflect cost-based rates. Currently, facts in this case appear to indicate that the rates for the agricultural class are beneath marginal cost much less EPMC levels. Bringing most of those classes below marginal cost up to such levels would require a large rate increase for some customer groups. The Commission recognizes that movement towards cost must be done in increments.

Agricultural interests should be put on notice today that the matter of their rates will be examined at length in 1990. A broad study of agricultural rates will be completed by November 5, 1990, so that the Commission can pinpoint where these rates fall with respect to their marginal costs, and EPMC. Once these studies are completed, they will provide a basis for changes in PG&E's rates. I urge the Commission to take the earliest procedural opportunity, such as the rate design window, to implement any changes. Should the studies, as predicted, reflect substantial gaps between current rates and more equitable cost-based rates, some ratepayer groups within the agricultural class may need to prepare for additional rate realignment.

Painful as these adjustments may be, in the long run, customers must make choices on electric use which reflect the cost of that use. At the very least, ratepayer groups must be prepared to shoulder the marginal costs of their utility service and not depend on other ratepayers to do so for them. Ultimately, the Commission has recognized that the movement of rates to EPMC will result in better utilization of resources and fairer rates. As we look to the future, we must put programs in place that appropriately value our resources in the interest of all ratepayers.

G. MITCHELL WILK, Commissioner

December 20, 1989
San Francisco, California

JOHN B. OHANIAN, Commissioner, Concurring:

I am generally very pleased to support this decision, and I offer congratulations to ALJ's Gregg Wheatland and Brian Cragg, as well as Commissioner Hulett and his advisors, for their efficient and sensible resolution of the many issues in the case. I offer the following specific comments:

Diablo Canyon. The Commission has made extra efforts to assure that the allocation of costs to Diablo Canyon is done correctly. The isolation of Diablo Canyon from conventional utility functions may presage similar Commission effort on other allocation problems, and it is important to get started on the right foot. I am disappointed that PG&E, in proposing that costs be allocated on an incremental basis, has such a short memory of the spirit and intentions of the settlement that was signed only a year ago. For example, it is irrational to assume that PG&E's management time spent on Diablo Canyon should be paid by ratepayers. The further studies that are ordered should remind PG&E that only cooperation and fair dealing can prevent Commission accounting oversight from becoming contentious and burdensome to both the utility and the Commission.

Management Incentive Plan. I am impressed with the ALJ's resolution of the funding of PG&E's proposed Management Incentive Plan (MIP). Such a plan should not be considered separately from management salaries. Rather than reviewing salaries and incentives independently, our mission should be to authorize reasonable management compensation levels, leaving the proper split of salaries and incentives to PG&E's discretion. We do not want to "micromanage" PG&E's compensation policies.

Productivity. I am intrigued by DRA's idea that future productivity studies should include capital costs as well the operating expenses conventionally studied, and I look forward to future work in that area.

Gain-on-Sale. Regarding disposition of gain-on-sale, I agree that this case should not be used to set Commission policy for future decisions. However, despite PG&E not meeting its burden of proof in this proceeding, I believe that disposition should be reserved until Commission policy is further developed. We intend to do so soon, in investigating the sale of Southern California Gas Company's office building. We have made many such deferrals in the past.

Economic Development Rates. I thank my colleagues for their support of my alternate language on economic development rates. The practical impact of the change is trivial because PG&E will likely not be adding new electric generating capacity during this rate case cycle. I urge that such rates be approved whether PG&E is short of capacity or not.

Agricultural Electric Rates. I concur with the adopted changes in the agricultural rate cap, downward from 5% to 2% over SAPC. I hope we are not leaving too much revenue to be allocated next year, with attendant "balloon payment" problems. We have resolved to move rates toward EPMC for all classes, but I am not entirely comfortable with our treatment of agricultural customers. I look forward to the upcoming studies of not only specific agricultural rates but if possible our approach to these rates in general.

Conservation Policies. I accept the revisions to the Proposed Decision regarding DRA's FEIP proposal. Reliance on the total resource test in approving programs will do little more than confirm current policy. As well, concentrating our efforts on energy efficiency and load management programs is essentially staying the course. I am concerned, though, that all incentive programs might be swept forward on the same basis as energy efficiency projects. I believe that the "free rider" problem, in which incentive beneficiaries would have undertaken conservation actions even without the incentives, deserves careful scrutiny. We may later wish to adopt different standards of review for incentive and non-incentive programs.

John B. Ohanian, Commissioner

December 20, 1989
San Francisco, California

FREDERICK R. DUDA, Commissioner, concurring.

I generally concur with the majority decision but have three specific concerns and several additional comments. The concerns are as follows: (1) I am concerned about our lack of progress towards full EPMC for the agricultural class; (2) I am concerned about the treatment of nonfirm incentives for large electric customers; and (3) I am concerned about lack of clarity in our policy framework for demand-side management (DSM) funding and implementation.

With respect to our lack of progress on agricultural rates, I believe that the Commission's continuation of a special rate cap for the agricultural class is of questionable benefit in the long run; we are merely forestalling the day when they must pay their fair share of the revenue requirement. In the meantime, the Ag class faces electricity prices which improperly signal their relative cost responsibility and merely delay necessary adjustments in their production and electricity use to some uncertain future. There is no free lunch in electricity cost allocation; we all pay when there are improper price signals through the inefficient production and use of other resources. While I am interested in the proposed additional marginal cost studies, I believe that the current marginal cost studies are quite refined and are certainly adequate to support further movements toward full EPMC for the Ag class.

With respect to the rate design for large industrial and commercial customers, I find the methodology for determination of nonfirm incentives confusing and possibly inconsistent. Again I suggest that proper price signals are important to increase our economic efficiency. As DRA and the large electricity users have suggested in comments, the method adopted to calculate nonfirm incentives may not properly consider the value of the interruptible service option. The decision may confuse the approach used for retail ratemaking with an approach using avoided cost for supply-side ratemaking. I find it surprising that the ALJ rejected a joint exhibit that resolved many of these related issues and was opposed only by TURN. Moreover, while most parties agreed with the use of a value-of-service basis for the under frequency relay (UFR) option, the ALJ rejected that approach in favor of an approach based on marginal coincident capacity cost. I raise these matters because of my concern for the long-term viability of utility service to large customers that are most able to leave the system. My recommendation for future nonfirm rate design, and for the upcoming workshop on this subject, is that parties actively pursue some common ground of agreement on a consistent approach for calculation of nonfirm incentives. Moreover, interested parties should focus on economically efficient alternatives to further unbundle the system which rely on value of service methods. The method proposed by DRA and PG&E for the under frequency relay option (UFR) is one such example where value-of-service is an appropriate basis for differentiation in rate design.

With respect to DSM, I believe that the decision could be somewhat more clear in its emphasis on the basis for funding various programs. While I find no fault with the funding levels chosen for programs, I am concerned that the Commission seems to have moved away from reliance on cost-effectiveness as the indicator of the extent to which DSM programs should be funded. I am also concerned about the Decision's relative silence regarding the use of the Rate-Impact Measure (RIM) Test, which indicates the change in rates and the change in utility contribution to marginal revenues resulting from use of DSM. I believe that utilities are very concerned about the effect that rate levels have on their competitive position and that the RIM Test should be used as a secondary test for the aggregate of all programs in a utility's DSM portfolio. I would also reinforce the majority opinion with respect to my support for use of the All Ratepayer Test, but again have a recommendation for future consideration in Commission DSM related proceedings; the All Ratepayer Test should be used to internalize environmental and social costs to the greatest extent possible to more properly guide future DSM funding decisions. As with our system of adders for avoided cost payments, the inclusion of environmental costs is appropriate and necessary in order to directly address issues related to regional and global environmental constraints. On the issue of the FEIPS, while I respect the hard work of the DRA in this regard, I will not support a complex and over-arching approach to DSM regulation such as the original FEIPs proposal provides. To reiterate, the Total Resource Test, with externalities included, provides substantial guidance on the efficiency of DSM options that compete to displace electricity as well as gas. In combination with the RIM Test, I find this information sufficient in most cases to guide the Commission in its consideration of resource options.

With respect to Women and Minority Business Enterprise (WMBE), I especially commend PG&E and its staff for their good work in making an excellent showing of progress toward meeting the WMBE goals set by General Order (GO) 156. As this order states at page 155, the reported WMBE business levels increased from $102 million (+) in 1987 to over $152 million (+) in 1988. PG&E has shown significant progress in bringing participation by minority and women owned businesses into their corporate expenditures. Since these advances were made within the system of required quality and price competition, this is truly a win-win result for PG&E, for MWBE organizations, and for all of California.

I also wish to comment on the Research Development and Demonstration (RD&D) section. I approve of the total program level of $36,732,000. Consistent with the recent past much of this program level sustains projects already underway. To the extent it can, PG&E should respond to our increased environmental concerns and redirect its focus to projects especially in the natural gas end use area, which can bring increased efficiency, economy, and environmental benefits (the three E's). There are opportunities for coordination of projects, and direct collaboration in the gas area. New gas burning engines, both stationary and mobile, together with new burner technology and NOx reduction are likely projects that deserve attention.

Lastly, I again commend PG&E and its staff for their excellent cooperation and support of the California Utility Research Council (CURC) and the California Institute for Energy Efficiency (CIEE). It has taken many hundreds of man hours to do the planning of past programs and in planning the future. The year 1990 and the new decade provide great opportunities for RD&D successes. We wish you well.

With these recommendations and comments I join today's majority opinion.

Frederick R. Duda

Frederick R. Duda, Commissioner

December 20, 1989
San Francisco, California

4. Generation capacity, as a ratio of the nameplate capacity of Diablo Canyon to the nameplate rating of all of PG&E's generating units.

PG&E vigorously criticizes DRA's special four-factor allocation. We agree with many of PG&E's criticisms.

First, PG&E correctly notes that the use of "gross plant" seriously overstates Diablo Canyon's impact on A&G costs. Diablo Canyon, as a new plant, represents 36% of total plant because it has a higher historical cost than other older plants on the PG&E system.

Second, PG&E states that the use of generating capacity and annual energy output weigh the allocation too heavily toward the size of the facility, such that the use of both amounts to double counting. PG&E objects that DRA has removed factors which do have a causal connection to common costs, such as the number of employees, and replaced them with factors which allocate a disproportionate share of costs based on production. We agree with PG&E that generating capacity and gross plant, the combination of factors selected by DRA, weighs the balance too heavily toward the size of the facility.

Third, PG&E properly observes that the use of "annual energy output" is totally defective when the plant is not operating. We see no possible causal connection between the energy output and administrative and general costs. Indeed, if the plant is not operating and requires additional repairs, maintenance, and management attention, Diablo Canyon related A&G expenses might actually increase; yet, DRA's four-factors would decrease the allocation.

In summary, we find that three of the four-factors in DRA's allocation do not bear a reasonable relationship to the costs to be allocated and are not a reliable means of estimating A&G expenses resulting from operation and maintenance of Diablo Canyon.

clear. We were therefore disappointed that PG&E's affirmative showing in support of a 1,400% increase in funding consisted of just three short paragraphs. At a minimum, PG&E's affirmative showing should have consisted of a reasonably detailed description of the new program and a direct response to each of the questions posed by the previous decision.

We remind CACD that our order directing that further workshops be held is still outstanding. We expect that workshops will be held in the near future. This proceeding will remain open for these workshops on management efficiency and incentives.

c. <u>Account 923: Outside Services</u>

Account 923 includes the fees and expenses of professional consultants and others for general services which are not applicable to a particular operating function or to other accounts. Account 923 also includes the pay and expenses of persons engaged for a special or temporary administrative or general purpose.

PG&E's estimate exceeds DRA by $6,653,000, due to use of a different methodology for estimating base expenses in this account. Before we discuss the 1990 forecast, we will review the difficulties encountered by DRA in obtaining an accounting of PG&E's outside service expenditures in 1987.

In November 1988 DRA requested a listing of outside services in 1987, with the accounts to which the amounts were booked. On December 30, 1988, PG&E provided a copy of FERC Form 2. In providing this list, PG&E explained:

> "This report is preliminary, in that it is subject to verification and change. It is the result of a substantial effort, and it represents the most complete data available at this time. Due to the volume of information and the number of documents that have to be examined to obtain this type of data, PG&E requests that staff focus on specific and significant vendors or charges in further data requests, if more information is needed, rather than on the list as a whole."

PG&E should specifically target and improve the participation of business enterprises owned by minority women.

In D.89-08-28, we recently clarified the question of goals relating to businesses owned by minority women. Specifically, we amended $ 6.3 of GO 156 to require that goals be established for both minority women owned business enterprises and non-minority women owned business enterprises. These goals are to be a subset of the overall goal for W/MBEs established by $ 6.2 (initially 20% for both women owned business enterprises and minority owned business enterprises). These goals are intended to ensure that utilities do not direct their W/MBE procurement programs toward non-minority women and minority men owned business enterprises to the detriment or exclusion of minority women owned business enterprises.

We also addressed the recording of contracts with minority women owned business enterprises toward compliance with the goals set forth in GO 156 $ 6.2. This section provides for initial long-term goals of not less than 15% for minority owned business enterprises and not less than 5% for women owned business enterprises, but does not specify a goal for minority women owned business enterprises. For the purposes $ 6.2, contracts with minority women-owned business enterprises can be counted toward either the minority owned business goal or the women owned business goal, but not toward both.

While we recognize the success to date of PG&E's W/MBE program, we agree that even a successful program can be improved. We urge PG&E to give serious consideration to each of the recommendations presented in the W/MBE Coordinator's testimony for improvement of its program. The W/MBE Coordinator may renew these recommendations, if necessary, in the next annual review of PG&E's W/MBE program.

D.88-04-057, as modified by D.88-09-024, requires the utilities to jointly establish a central clearinghouse for the

Resource Plan Update proceeding, and the resource plan used in the general rate case is not precedent for or binding on the resource plans developed in the BRPU. In the general rate case, however, the parties' perceptions of the need for new resources colors their positions on demand-side management, RD&D, and marginal energy costs.

VI. Energy Reliability Index

The ERI serves several functions in the general rate case, including modifying the marginal generation capacity cost, derive demand charges, and develop certain elements of revenue allocation and rate design.

Calculation of the ERI compares the utility's target reserve margin with the reserve margin resulting from forecasts of the utility's demand and resources for individual years. The primary elements of this comparison are the forecast of demand, the forecast of available resources, and the target reserve margins. These elements are closely related to long-term planning issues, and only PG&E and DRA made complete presentations on ERI issues.

A. Demand Forecast

All concerned parties agreed to use the demand forecast developed by the CEC for ER-7 (See Exhibit 138, pp. 3-4; Exhibit 70, App. D).

B. Target Reserve Margin

The parties now agree that the CEC's adopted target reserve margin of 17.5% should be used, although DRA argues that using this figure requires some adjustments to certain resource assumptions. DRA's positions are discussed and resolved in the following section.

Second is the assumption that the combustion turbine is the source of additional generation capacity, rather than just a proxy useful for estimating shortage costs. We think an ERI of less than 1.0 signals that resources other than the combustion turbine may be the sources of marginal generation capacity. The obvious example of this is capacity supplied by QFs. Payments for capacity supplied by QFs are based on the combustion turbine adjusted by the ERI, and the utility may reasonably be assumed to rely on such QFs for marginal generation capacity, rather than to install a combustion turbine. 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 to reflect lower-priced sources of marginal generation capacity is also consistent with the conception of the combustion turbine as the maximum shortage cost.

Some parties have criticized the ERI for its volatility. We share these parties' concern that this volatility is undesirable when it affects rates. Taking the six-year average ERI suggested by DRA for use in revenue allocation and rate design provides not only rate stability, but also a reasonable balance between long-run and short-run assessments of the need for and cost of generation capacity.

The values for the six years of ERIs for this proceeding should be derived from the long-term resource plan. The average of the EIRs for the six years beginning with the test year is 0.42. 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 BRPU proceeding will likely be the primary source of future series of ERI projections.

We conclude that it is appropriate to adjust the full annualized cost of a combustion turbine of $56.17/kW-yr. by the six-year average ERI of 0.42 to develop the marginal generation capacity cost of $23.59/kw-yr. used for revenue allocation and rate design in this proceeding.

2. Marginal Transmission Capacity Costs

Marginal transmission capacity costs reflect the cost of serving an additional kW of demand at the transmission system's peak.

DRA and PG&E agree that this cost should be calculated by referring to data on demand-related transmission additions and load growth for ten historical and five forecast years. DRA also agrees with PG&E's basic estimate of these costs of $32.19/kW-yr., which includes DRA's recommended treatment of large transmission additions and TURN's proposals for changes to the general plant loading factor. DRA would add an adjustment for franchise fees and uncollectibles, and PG&E does not oppose this addition to its basic figures. TURN appears to support this resolution.

We will adopt $31.80/kW-year, the costs agreed to by PG&E and DRA, as the marginal transmission capacity costs.

3. Marginal Distribution Capacity Costs

Marginal distribution capacity costs are the costs required to serve an additional kW of peak demand on the distribution system. There are two components, corresponding to the primary and secondary distribution systems. The distribution system performs both a capacity or demand-related function and a customer access function. Demand-related costs are allocated to marginal capacity costs, and costs required to provide a customer with access to the system are allocated to marginal customer costs. The distinction between these two functions is not clear, since the same equipment can serve both functions, particularly at the secondary distribution level. Allocating costs between these functions can become controversial, and the disputes about this allocation are addressed in the discussion of both marginal capacity and marginal customer costs.

Within the range of revenue increases that have been discussed in this case, application of a cap of 5% plus SAPC requires caps for only the agricultural and small light and power classes, and the 5% limit keeps these increases within a range that we find reasonable in light of all the circumstances. Other proposals either move too slowly toward EPMC or result in unbearably large increases to some classes.

One exception we will make to CLECA's proposal has to do with the treatment of the streetlighting class. CLECA imposed its floor of 5% below SAPC on this class. Other parties advocated the immediate reduction of this class' revenue responsibility to EPMC levels. We believe that we can and should make substantial progress toward reducing the burden on this class. For this case, therefore, we will move one-third of the way toward the EPMC allocation for the streetlighting class. We will also state our intent to continue this reduction in the next three years, so that the streetlighting class will receive its EPMC allocation in the next general rate case. Whether or not we are able to carry out this intent will depend on the circumstances that we will face in the next three years. We agree with many of the parties that the shift of revenues and the effect on other customers resulting from this action will be fairly minor.

The revenue shortfall due to the application of caps and the movement of the streetlighting class toward EPMC should be recovered, as CLECA suggests, from all uncapped classes on an EPMC basis.

In addition, we agree with many parties that a revenue allocation based on these principles should take place whenever there is a substantial change in revenue requirement. The most likely and logical forum for these allocations is the ECAC case. The marginal capacity and customer costs we adopt in this decision should be used in performing this allocation.

sales made under Schedule AG-5. This argument supports ACWA's position that the revenue shortfall associated with Schedule AG-5 should be shared by all classes.

We will adopt DRA's approach to intraclass revenue allocation. DRA's recommendation is consistent with our adopted approach to interclass revenue allocation, and the recommended caps and floors are in line with the positions of several other parties.

B. <u>Allocation to Residential TOU Schedules</u>

The assignment of revenue responsibility to the schedules of the residential class is complicated because parties have proposed two new TOU schedules. PG&E proposed a new Schedule E-8, and DRA proposed a new Schedule E-9. The details of these schedules are described in the rate design section of this decision.

Although DRA and PG&E agree to a large extent on how to allocate revenue to the residential schedules, two major differences remain. First, PG&E did not include DRA's proposed Schedule E-9 in its allocation, because it opposes this schedule. This issue will be resolved when we decide the disposition of the proposed schedules in the section on rate design.

Second, the parties differ in their estimates of the usage characteristics and number of customers on the new TOU schedules.

PG&E's approach relies on a number of assumptions about the average usage by customers on the new schedules, the average rate for those schedules, and the number of customers who are likely to take service under the new optional schedules.

DRA argues that it refined a number of PG&E's assumptions and thus its results are more reliable than PG&E's.

TURN's allocation to residential schedules includes a proposal for a revenue-neutral allocation to the existing TOU option, Schedule E-7. As an alternative to this recommendation, demand-related portion of marginal transmission capacity costs). Second, PG&E has indicated that curtailable service has the potential to avoid all but 0.06% of coincident demand-related capacity costs under current circumstances. Third, we believe that the emergency functions of the nonfirm program are important and perhaps undervalued by the available economic approaches. And fourth, the level of this incentive should be in the proper proportion to the incentives for the other elements of the nonfirm program.

After considering these factors and the limited record on this point, we adopt the incentive initially recommended by DRA, $16.28/kW-year, as the incentive for customers with UFRs. In adopting this amount, we should make clear that we have not approved the approach DRA took in reaching this figure. DRA's recommended incentive is adopted because it is the number presented in the record that best represents our balancing of the considerations we have just discussed.

Under the terms of the joint exhibit, the annual interruptible incentive is to be converted to a cents/kWh basis and paid as a credit against the interruptible customer's monthly energy use.

The question of the proper level of nonfirm service incentives should be considered again in the near future. We have already suggested some of the information and analyses that we would find helpful in resolving this issue more satisfactorily. Information on how PG&E uses interruptible customers to deal with unexpected disruptions, perhaps enhanced by computer simulations, would help in defining the specific costs that should be considered in setting interruptible credits. Information on the costs of measures like increasing spinning reserve, improving reliability measures, and purchasing emergency capacity, which may be viewed as functional alternatives to the UFR program, would also be helpful. We will direct PG&E to submit a study and proposal on nonfirm rates

As a general matter, we agree with DRA that the components of agricultural rate design should reflect their costs. In the past, we have attempted to avoid disruptive rate increases to agricultural customers, and we have taken such steps as capping the revenue allocation to the class and introducing many service options to reduce customers' bills. Cost-based rates are another way to reduce to the cost of service to the class and avoid allocation-based increases by lowering the revenue allocation to the class.

2. <u>Customer Charge</u>

Both DRA and PG&E recommend a $10 monthly customer charge for agricultural accounts. We will adopt the parties' recommendation.

3. <u>Maximum Demand Charges</u>

Both PG&E and DRA agree that the increase to maximum demand charges to Schedules AG-1, AG-R, AG-V, and AG-4 should be capped consistently with the overall percentage cap used in intraclass rate design. The parties differ, however, in the specific calculation of the cap.

PG&E sets the cap at the sum of the interclass and intraclass caps for the agricultural class. PG&E believes that its recommendations result in moderate increases that permit sufficient movement toward EPMC, especially in light of the substantial increases in demand charges that resulted from the reorganization of agricultural schedules in 1987-88.

DRA caps the increases to these schedules at five percent over the total cap on intraclass and interclass agricultural revenue allocation. DRA believes that a more aggressive movement to EPMC is warranted because the maximum demand charges for these schedules remain considerably below their EPMC levels. Although the resulting percentage change may seem large, the bill impact of its recommendation is still within DRA's goal of limiting the effects on individual customers' bills.

185. The parties agree that the CEC's adopted target reserve margin of 17.5% should be used to calculate the ERI.

186. D.89-06-048 adopted a formula for calculation of the ERI that differs slightly from the one PG&E and DRA used in their original testimony.

187. D.89-06-048 chose an exponential, rather than a linear, formula, adopted a floor value of 0.4, and required use of the target reserve margin the CEC adopted in ER-7.

188. Use of the 17.5% target reserve margin of ER-7 and the associated "age-derating" of capacity from oil- and gas-fired generating plants reduces the capacity of these plants in PG&E's service area by a cumulative total of 489 MW by 1992.

189. The determinations of this decision result in the ERIs shown in Appendix H. The average for the six years beginning with the test year is 0.42.

190. DRA recommends adjusting marginal capacity and customer costs for franchise fees and uncollectibles (FF&U).

191. TURN points out that the general plant loading factor (GPLF) used by PG&E improperly included costs related to gas distribution.

192. PG&E and DRA agree that use of the annualized cost of a combustion turbine results in an estimate of marginal generation capacity costs of $55.69/kW-yr.

193. The ERI was originally developed as a way to adjust the capacity prices paid to QFs to reflect the value of the additional capacity supplied by QFs to the utility's system. The ERI was developed to offer a way of reflecting the value of additional capacity to the system over a range of relationships between resources and demand.

194. Taking the six-year average ERI suggested by DRA for use in revenue allocation and rate design provides not only rate stability, but also a reasonable balance between long-run and

214. A single agricultural customer can have multiple accounts, and the diversity of the accounts is accurately reflected by measurements of maximum demand at the final line transformer.

215. A new generating plant may be more reliable than the existing mix of resources and may permit a decrease in the target reserve margin.

216. When a utility's actual reserve margin is well above its target reserve margin, an increase in demand does not require any addition to reserves.

217. In this case, all parties endorse the EPMC approach to interclass revenue allocation with limits (caps and floors) to moderate the rate effects on particular classes.

218. Revenues from special contracts often differ from the revenues that would be collected if customers with special contracts were served under the appropriate tariffs.

219. Removing all sales and revenues associated with special contracts from the allocation process leaves the relationships among the other classes unaltered.

220. In PG&E's last general rate case we distinguished between revenues from tariff rates that recover the types of costs that are included in the revenue allocation (allocated revenues) and revenues that reflect other types of costs or savings (nonallocated revenues).

221. Schedule AG-5 applies to a large group of customers, with many varying circumstances.

222. The rate for Schedule AG-5 is close to marginal cost.

223. The agricultural class has a greater fluctuation in sales than other classes.

224. Generation reliability problems affect all customers equally, not just rural customers.

225. PG&E and DRA differ in their estimates of the usage characteristics and number of customers on the new residential TOU schedules. DRA refined a number of PG&E's assumptions.

292. PG&E's cost of painting streetlighting poles averages $0.82 per pole per month.

293. High pressure sodium vapor facilities served under Schedule LS-1, Class B would be charged identical rates if they were served under Class A.

294. DRA proposes "Funding, Evaluation, and Implementation Principles" (FEIP) for DSM. The FEIP consist of some 65 individual tenets covering all aspects of PG&E's current DSM program.

295. We have stated a series of principles for evaluating DSM programs in the various decisions we have made on DSM issues over many years. Many of the tenets of the FEIP are restatements of policy determinations we have already made.

296. The current relation of marginal costs to average retail rates leads to low benefit-cost ratios for the RIM.

297. PG&E proposes to consolidate the existing Direct Weatherization, Low-Cost Weatherization, and Community Weatherization programs under the TCDAP to reduce administrative costs and improve the Direct Assistance programs' cost-effectiveness.

298. Because of the high cost of retrofitting, the cheapest time to extend gas lines into new developments is when they are under construction.

299. Under the TRC test, incentive programs have very high benefit-cost ratios.

300. Spending on the Energy Efficiency Incentive program dropped considerably in 1989 compared to 1988.

301. The Area Development Program is part of a coordinated effort on the state and local levels to stimulate economic growth in certain depressed areas. These economic benefits, in combination with the relatively small amount devoted to this program, outweigh concerns about long-term costs.

75. Class coincident demands for 1990 should be estimated using historical load factors derived from 1985, 1986, and 1987 load data, weighted by PG&E's hourly generation loss of load probability (LOLP) forecasted for 1990. Each class' hourly loads for each of the historical years should be scaled so that multiplying each year's hourly percentage times PG&E's expected system loads for the test year produces the test year's sales forecast.

76. Marginal generation capacity costs should be allocated entirely on the basis of coincident demand.

77. The diversity of customers' maximum demands should be reflected in the noncoincident demand as measured at the final line transformer.

78. DRA's allocation of marginal transmission and distribution capacity costs is reasonable.

79. DRA's proposal to increase marginal generation capacity costs by the percentage of the target reserve margin should not be adopted.

80. In this case, application of a cap of 5% plus SAPC requires caps for only the agricultural and small light and power classes, and the 5% limit keeps these increases within a range that we find reasonable in light of all the circumstances.

81. It is reasonable in this case to move one-third of the way toward the EPMC allocation for the streetlighting class. This reduction should continue during the next three years, so that the streetlighting class will receive its EPMC allocation by the next general rate case.

82. The revenue shortfall due to the application of caps and the movement of the streetlighting class toward EPMC should be recovered from all uncapped classes on an EPMC basis.

83. A revenue allocation based on the principles we adopt in this case should take place whenever there is a substantial change in revenue requirement during the rate case cycle. The marginal

capacity and customer costs we adopt in this decision should be used in performing this allocation. In these subsequent allocations, we will use caps and floors of SAPC plus or minus 5% as a guideline in developing a revenue allocation, except for the streetlighting class.

84. The ideal allocation of revenues from special contracts would maintain the relationships among the customer classes that would exist if the need for special contracts had never arisen.

85. Removing all sales and revenues from special contracts from the allocation process results in a reasonable treatment of revenues from special contracts.

86. Capacity savings from nonfirm service and load management programs should be credited against these customers' rates. The revenue allocation should then spread the costs of the associated discounts to all customers.

87. Revenues from Schedule AG-5 should be included in the revenue allocation like revenues from any other tariff schedule.

88. A separate ERAM account for the agricultural class is not reasonable.

89. AWCA has failed to show that any substantial benefits are likely to result from investigating whether all water pumpers should be classified as agricultural customers.

90. ACWA has failed to develop a record to support a reliability adjustment for rural customers.

91. The revenue allocation to schedules within a particular class should be bounded by a cap or floor of 5% above or below the class' average percentage change that results from the interclass allocation.

92. DRA's approach should be followed in developing the usage characteristics, number of customers, and resulting revenue allocation to the new residential TOU schedules.

93. The residential customer charge recommended by DRA is not reasonable at this time.

to reduce their electric bills and the load they place on the system.

176. A $10 monthly customer charge for agricultural accounts is reasonable.

177. It is reasonable to adopt a cap for the maximum demand charges of Schedules AG-1, AG-R, AG-V, and AG-4, set at the level of 5% above the sum of the interclass and intraclass percentage caps.

178. DRA's recommendations for determining maximum demand charges for Schedules AG-5A, AG-5B, and AG-5C, subject to a floor of current charges, are reasonable.

179. On-peak demand charges for agricultural TOU schedules should be set at EPMC levels.

180. The demand charge limiter is designed to allow minimal energy use during a particular season. If the customer is recording more than the allowed minimal use, then that customer is not truly a seasonal customer of the sort that the demand charge limiter is designed to protect.

181. CFBF's proposal to apply demand charge limiters to the "A" series of agricultural tariffs should not be adopted.

182. For the next rate case cycle, the demand charge limiter should be retained for the agricultural class with the increases advocated by DRA.

183. TOU energy charges for the agricultural class should be set so that the average rate in each TOU period is proportional to the combined marginal cost of energy and coincident capacity for each TOU period.

184. The incremental cost of agricultural TOU metering above standard meter costs should be added to allocated revenues for TOU schedules to produce the total revenue requirement. The meter charges on agricultural TOU schedules should be set at the incremental cost of TOU metering, rounded to the nearest five cents.

204. The primary purpose of the Natural Gas Home program is to overcome market barriers to installing efficient natural gas appliances.

205. PG&E has not adequately justified the need for the fuel substitution portion of its electric heat pump incentive program.

206. PG&E has failed to justify its Efficient Outdoor Security Lighting program.

207. A reasonable budget for the Area Development program is $1,000,000 for the electric program and $500,000 for the gas program.

208. PG&E's and DRA's installation goal of 20,000 TOU meters per year is reasonable. PG&E should continue to report on the progress of the voluntary TOU program as part of its annual ECAC cases.

209. Installing 20,000 TOU meters annually should be viewed as a minimum, and PG&E's estimated market saturation dates should be a goal, rather than merely an estimate. By the time of PG&E's next rate case, PG&E should have a well-developed plan for completing the saturation of the various markets for TOU meters.

210. PG&E should vigorously promote the planting of shade trees in its service territory. A coupon program targeted to specific areas or groups of customers should be part of this program.

211. PG&E should seek to maximize the cost-effectiveness of its incentive programs.

212. The DSM budget set forth in Table 8 is reasonable.

213. The rate increases authorized by this decision should be reduced by the available unspent DSM and RD&D funds from PG&E's last general rate case cycle.

INTERIM ORDER

IT IS ORDERED that:

1. The Commission Advisory and Compliance Division (CACD) shall investigate the extent to which conservation has led to reduced baseline quantities. The report of this investigation will be due on April 1, 1990. Copies shall be served on the Commissioners, the assigned Administrative Law Judges, the Division of Ratepayer Advocates (DRA), Pacific Gas and Electric Company (PG&E), and any other party requesting a copy.

2. PG&E shall continue to work with the Public Advisor's Office to develop notices that are meaningful to those who do not speak English.

3. PG&E is authorized and directed to file with this Commission on or after the effective date of this order, and at least three days prior to their effective date, revised tariff schedules for electric rates as set forth in Appendixes.

4. The revised tariff schedules shall become effective on or after January 1, 1990 and shall comply with General Order 96-A. The revised tariffs shall apply to service rendered on or after their effective date.

5. All transcript corrections received are incorporated in the record.

6. PG&E is authorized to file attrition adjustments for 1991 and 1992 based on the results of operation adopted in these Appendices.

7. PG&E shall adjust its Electric Revenue Adjustment Mechanism (ERAM) effective January 1, 1991 to reflect full implementation of the guidelines for plant held for future use contained in Appendix L. The guidelines shall apply to all plant held for future use regardless of the date of acquisition.

28. PG&E shall submit a study and a proposal on nonfirm rates. The ALJ shall arrange for informal meetings or formal hearings, as necessary, to achieve the goal of refining the nonfirm incentives.

29. PG&E is authorized to offer the economic dispatch option described in Exhibit 88, subject to the modifications suggested in this decision.

30. For this rate case cycle, PG&E shall report annually on the results of implementing and operating the economic dispatch option and submit the option to annual review. This report and review shall take place in connection with the reasonableness phase of the Energy Cost Adjustment Clause (ECAC) proceeding.

31. PG&E is authorized to withdraw Schedule E-24.

32. PG&E is authorized to offer DRA's proposal for a new option, derived from Schedule E-25, as a new tariff designated as Schedule B-26.

33. PG&E is authorized to offer an experimental Schedule E-11, based on the proposal of the Association of California Water Agencies (ACWA), as modified by PG&E.

34. PG&E shall work with DRA in reviewing the initial results of the experimental Schedule A-RTP, before expanding the program in 1991.

35. PG&E shall revise its tariffs to apply the average rate limiter to all of a standby customer's regular service load, subject to the limitations described in this decision.

36. PG&E, as part of its next general rate case, shall submit a study of the costs of metering and obtaining the data needed to distinguish between the different types of standby service.

37. PG&E is authorized to withdraw the unconventional technology allowance of Schedule S.

38. PG&E is authorized to offer experimental Schedule subject to the limitations stated in this decision.

39. PG&E is authorized to eliminate the minimum bill for Schedules AG-5A, AG-5B, and AG-5C.

40. PG&E shall install the necessary time-of-use (TOU) meters by May 1, 1990 to allow current customers on Schedule AG-6 to convert to TOU schedules.

41. PG&E shall submit a report stating the number of agricultural TOU meters installed in 1989, the number of requests for conversion received in 1989, by month and by schedule, the backlog by schedule existing at the end of 1989, and the average delay in responding to a request for conversion. The report will be due on March 15, 1990, and shall be served on the California Farm Bureau Federation (CFBF), the Power Users Protection Council (PUPC), ACWA, DRA, and any other party making a specific request to PG&E.

42. PG&E's proposal to transfer the high pressure sodium vapor facilities served under Schedule LS-1, Class B, to Class A, is authorized.

43. PG&E shall continue to report on the progress of the voluntary TOU program as part of its annual ECAC cases.

44. PG&E shall continue to file an annual report, by no later than March 1, 1990, of its hazardous waste program and related expenditures.

45. PG&E shall file an advice letter, no later than October 1, 1990, to true-up test year 1990 ratemaking federal income tax expenses, consistent with D.89-11-058. The resulting difference in revenue requirement shall be included in PG&E's 1991 attrition adjustment.

46. The Petition OF DRA to set aside submission and reopen the general rate case on the issue of an adjustment to account 925, relating to fallout-type particulate pollution claims is granted. The issue of Account 925 is reopened to permit all parties to submit updated information on all expenses included in Account 925.

Funds authorized for Account 925 in this decision shall be subject to refund, pending our final decision on this account.

47. If PG&E receives a variance from the Regional Water Quality Control Board for its surface impoundment program, PG&E shall consult with DRA to identify other appropriate environmental-related uses for the amounts saved by the issuance of the variance.

48. PG&E shall report in its next general rate case application on the progress, costs and benefits of the 500 kV bare hand live-line training program.

49. In future general rate case and offset applications, PG&E shall show then current revenues by customer class for each revenue account in PG&E's preliminary statement. PG&E shall clearly segregate retail revenues for which the Commission sets rates from all other revenues. PG&E shall separately describe te revenue relief requested for retail customers and for all other customers.

50. Pacific Gas and Electric Company is authorized and directed to file with this Commission on or after the effective date of this order, and at least three days prior to their effective dated revised tariff schedules for gas rates derived from revenue changes as set forth in Appendixes such rates to be calculated as set forth in D.89-09-094.

This order is effective today.

Dated ____________________, at San Francisco, California.

APPENDICES G, H, I, AND J will be supplied at a later date.