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Decision 91-05-029 May 8, 1991

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

Application of PACIFIC GAS AND ELECTRIC COMPANY for authority to revise its gas rates and tariffs effective April 1, 1991, pursuant to Decision Nos. 87-12-039, 89-01-040, 89-05-073, and 90-04-021. Gas (U 39 G)	Application 90-08-029 (Filed August 15, 1990)

INTERIM OPINION

(See Appendix A for appearances.)

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I. Summary

This decision resolves issues raised in Pacific Gas and Electric Company's (PG&E) third annual cost allocation proceeding (ACAP). PG&E's bundled core rates will decrease by .3%, or $5 million and its non-core transportation rates will decrease by 9.2% or $42 million.

We adopt in its entirety a stipulation reached by the following parties: PG&E, the Division of Ratepayer Advocates (DRA), the Canadian Producer Group (CPG), the City of Palo Alto, Southern California Edison Company (SCE), and Toward Utility Rate Normalization (TURN). This stipulation settles most of the traditional ACAP issues and we find it is in the public interest. We commend the parties for settling most issues in light of the uncertainties over the Gulf war and the upcoming changes in the gas industry structure.

Issues not resolved by the stipulation will be discussed in the sections below.

II. Procedural Background

PG&E filed its application in the above-captioned proceeding on August 15, 1990, pursuant to the schedule set forth in Decision (D.) 89-01-040, the rulemaking which revised the time schedule for rate cases and fuel offset proceedings. This is the third ACAP which PG&E has filed. The test period at issue in this ACAP is April 1, 1991 through March 31, 1992. The ACAP is a forecasting proceeding, where the Commission sets rates for all customers which are based on an estimate of likely revenues at cost based rates and also includes an adjustment for a reasonable amount of discount. Ordinarily, some discounting is expected, because large customers have the market power to use cheaper options by purchasing oil, propane, or other alternative fuels.

In its application filed in August, PG&E requested authority to increase gas rates, as of April 1, 1991, by approximately $99.1 million, reflecting a decrease in the procurement revenue requirement of $45.9 million and an increase in the transportation revenue requirement of $144.9 million. However, as the proceeding progressed that request has changed dramatically. The stipulation called for overall revenue requirement reduction of some $42 million to be updated in January 1991. The January 31, 1991 update indicates a net rate decrease of approximately $139,643,000. This decrease is a result of a $128,539,000 decrease in the procurement revenue requirement, and a $11,104,000 decrease in the transportation revenue requirement.

The first prehearing conference (PHC) was held in mid-September. The assigned administrative law judge (ALJ) ordered PG&E to file a supplement to its application to address issues raised by the invasion of Kuwait by Iraq, and the 1990 Canadian price redetermination. PG&E's supplemental testimony was submitted to the parties on September 28, 1990.

On October 19, 1990, PG&E filed a motion to limit the scope of this proceeding due to the issuance of D.90-09-089, the natural gas procurement rulemaking in OIR 90-02-008. Since the procurement OIR decision will impact the structure of non-core rates beginning August 1, 1991, PG&E sought to limit the scope of this proceedings to a revision of core rates. At the second PHC of October 22, 1990, TURN also proposed a revised ACAP schedule. The assigned ALJ denied PG&E's motion and rejected the schedule proposed by TURN. Hearing dates were then set in an effort to meet the April 1, 1991 effective date for ACAP rates.

In light of the uncertainties caused by the Gulf war and the upcoming changes in the gas industry, PG&E, DRA, and TURN met in an attempt to reach agreement on various issues in this proceeding before the hearings were scheduled to begin in November. On November 13, 1990, the first day of scheduled hearings, the three parties informed the assigned ALJ that a joint position had been reached on the major issues in this proceeding. In light of the pending stipulation, and in an attempt to have other parties join in a stipulation, the ALJ revised the hearing schedule. Informal workshops on the proposed stipulation were set, and hearing dates were set for the remaining issues that were not agreed upon. A formal settlement conference was then noticed for November 27, 1990 pursuant to Rule 51.1(b) of the Rules of Practice and Procedure of the Commission. At the same time, PG&E filed a motion for waiver of Rule 51.6(c).

Hearings were first held on issues that were not part of the stipulation. These issues were the cogeneration shortfall account (CSA), the cogeneration transportation rate, and the long-term contract revenue allocation. As to the issues addressed in the stipulation, it was determined that the underlying prepared testimony of stipulating parties should be put into the record. This was done in order to accommodate Salmon Resources Ltd. who did not sign the stipulation and wished to examine the settling parties on their underlying testimony. All witnesses requested by Salmon Resources Ltd. were made available for cross-examination. No other party requested an opportunity to examine these witnesses. In accordance with the stipulation, the parties to the stipulation did not cross-examine each other on their underlying prepared testimony.

After the formal settlement conference on November 27, 1990 the stipulation was filed with the Commission and later admitted into evidence as Exhibit 27. (Attached as Appendix D.) The stipulation was signed by PG&E, DRA, CPG, the City of Palo Alto, SCE, and TURN. A panel made up of representatives for PG&E, DRA, and TURN were made available for cross-examination by Salmon Resources Ltd. on the terms of the stipulation. The motion filed by PG&E for a waiver of Rule of 51.6(c) was then granted. While the timing was handled differently, the goals of the settlement rules had been reached in this proceeding. Salmon Resources Ltd., the only party who wished to contest the stipulation was in agreement with the way the assigned ALJ handled the proceeding.

It was determined that combined briefs on both the stipulation and issues that were not part of the stipulation would be filed on January 8, 1991 with reply briefs comments due January 23, 1991. In addition, it was agreed that an update exhibit would be filed containing January 31, 1991 balancing accounts amounts. This update exhibit was filed on February 19, 1991 and will be marked as Exhibit 28 for identification. Parties were directed that they may comment on the accuracy of the update exhibit in their comments on the ALJ's proposed decision. Thus, this phase of A.90-08-029 was submitted on February 19, 1991.[1]

Comments on ALJ's Proposed Decision

Comments on the ALJ's proposed decision were filed by PG&E, DRA, TURN, CIG et al., and CCC. Gasmark Inc., Gasmark West Inc. and Mock Resources Inc. filed a Joint Petition for Leave to Intervene which is hereby granted for good cause shown. Joint comments were timely filed by Gasmark Inc., Gasmark West Inc., Sunrise Energy Company, Sunpacific Energy Management Inc., Salmon Resources Ltd. and Mock Resources, Inc. (Gasmark et al.).

Meridian Oil Inc. filed comments late and is not a party to this proceeding. Thus, Meridian Oil Inc.'s comments were properly rejected by the Commission's Docket office for filing.

All the timely filed comments have been reviewed and carefully considered by the Commission. Any changes or additions required by the comments have been incorporated in this decision.

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1 A second phase of this proceeding has been created to address the issue of whether PG&E's December 1990 brokerage fees study merits hearings or not. Prehearing conferences on that issue were held on February 1 and March 22, 1991. Hearings have been scheduled for May 1991.

III. Stipulation Issues

The stipulating parties stress that given the uncertainty of the war in the Middle East and its impact on future oil prices as well as the upcoming implementation of D.90-09-089, the stipulation is a reasonable compromise of the various positions of the parties as set forth in their prepared testimony. The stipulating parties agreed that it would be improper to give their stipulation any precedential weight in any future PUC proceeding. Finally, the stipulating parties stressed that the numbers agreed upon for various elements were not intended to have a relationship to each other but were simply an effort to reach compromises that were reasonable. The stipulation for the most part is not contested. Only one party, Salmon Resources Ltd., chose to cross-examine the stipulating parties on any of the underlying issues. In its brief, Salmon indicates that it is only challenging one aspect of the settlement, the appropriate direct-billed take or pay costs. California Industrial Group, California Manufacturers Association, and California League of Food Processors (CIG et al.) have challenged the balancing account treatment proposed by the stipulation. Both of these contested elements will be discussed in a later section of this decision.

A. Uncontested Elements of the Stipulation

1. Forecast of Crude Oil Prices

The forecast of alternate fuel prices is a critical element in the ACAP. This is because of its connection to the forecast of the amount of revenues PG&E can expect to collect from its non-core transportation customers. Usually, this revenue forecast incorporates a forecast of discounting to non-core customers which is largely based on the forecast of crude oil and natural gas commodity prices. Thus, because of the direct relationship between the crude oil price forecast and the non-core transportation revenue forecast, the crude oil price forecast traditionally is hotly contested issue in an ACAP proceeding.

a. <u>Original Positions of Parties</u>

Due largely to the invasion of Kuwait by Iraq, PG&E was ordered to file supplemental testimony. PG&E claims it took the Gulf conflict into account in forecasting the refiners average acquisition cost of imported crude oil (RAAC) to average $20 per barrel during the ACAP period. DRA, on the other hand, recommended adoption of a RAAC of $29.15 for the ACAP period. In light of the tremendous uncertainty regarding any oil price forecast, PG&E, DRA, and TURN made a variety of proposals to use an updated forecast using the average of three independent oil price forecast.

b. <u>Stipulation Position</u>

The stipulating parties expressly recognized the extreme uncertainty surrounding world oil markets and any forecast of a crude oil price caused by the war in the Middle East. In light of this uncertainty, the stipulating parties recommend that instead of forecasting a crude oil price and using it to derive the expected level of discounting to non-core customers, the Commission adopt the specific discounting levels set forth in the stipulation for the G-IND, G-P2B, and G-COG classes.

c. <u>Discussion</u>

Unlike last year's ACAP proceeding, the disparity between PG&E's and DRA's oil price forecast in their original testimony is quite dramatic. Twenty dollars per barrel versus twenty nine dollars per barrel is indicative of extreme uncertainty surrounding oil prices due to the Gulf war. At best, forecasts are sophisticated guess work of so-called experts in the field. We concur with the stipulating parties that the approach reached in their stipulation (Appendix D) is a reasonable outcome given the circumstances that surround this ACAP period. The stipulation correctly incorporates an implicit assumption that oil prices will be high enough so that only minimal discounting will occur, yet recognizes the uncertainty by incorporating a 90% balancing account for non-core transportation revenues. (The 90% balancing account issue will be discussed in a later section of this decision.) We agree with the stipulating parties that no specific crude oil price should be adopted, but the minimal discounting in the stipulation, embodying an implicit assumption of relatively high oil prices, shall be adopted.

2. Cost of Natural Gas

In a typical ACAP proceeding, the appropriate forecast of the cost of gas for the utility is an important piece of the current gas industry structure. Under the current program, (which is due to change August 1, 1991) the utility sells gas to its customers from either the core portfolio or the non-core portfolio. Core customers are served exclusively by the core portfolio which is comprised entirely of secure long-term supplies. Non-core customers can purchase gas from either the non-core portfolio, which is comprised largely of short-term gas, or the core portfolio. They also have the option of purchasing gas from someone other than the utility and transporting it over the utility system. Core ratepayers are indifferent as to whether or not non-core customers buy gas from the utility or someone else since the utility is required to sell the gas at cost. The utility's non-core margin (except Utility Electric Generation (UEG)) is recovered entirely through the transportation rate.

In an ACAP, estimates of the weighted average cost of gas (WACOG) for both the core portfolio and the non-core portfolio are developed. The core WACOG is used to developed the commodity component of core rates.

Unlike past ACAP proceedings, development of an estimate of the non-core customers commodity cost of gas is less important. The stipulation reflects an implicit assumption that the price of oil will be so high relative to the commodity price of natural gas during the test period that only minimal discounting will be necessary. Thus, no further estimate of the commodity cost of natural gas purchased by non-core transportation customers is necessary.

a. Core WACOG

1) Original Positions of Parties

In their original testimony, several parties forecast core WACOGs. PG&E estimated a core WACOG of $2.31 per decatherm (Dth), while TURN forecasts a core WACOG of $2.18 per Dth. DRA predicted a core WACOG of $2.16 per Dth, and finally CPG forecasts a core WACOG of $2.17 per Dth.

2) Stipulation Position

The stipulation selects a core WACOG of $2.23 per Dth. This does not include any balancing account component, or brokerage fees or allowances for franchise fees and uncollectables expense, all of which would be described in a later section of this decision. The stipulation intentionally does not address any of the underlying assumptions which the parties used in their original testimony to develop a core WACOG forecast. While the stipulating parties are able to agree that $2.23 per Dth is a reasonable forecast of the core WACOG, the parties do not agree on the underlying components of the forecast. The parties contend that it is not necessary for them to do so. They point out that it is not the underlying assumptions but the core WACOG itself which is used to develop the procurement components of rates.

While their original testimony focuses on the differences in their underlying assumptions, parties in fact agree on many points. All stipulating parties agree that Canadian gas will comprise a substantial component of the core portfolio. All stipulating parties agree that gas from U.S. Southwest will comprise another substantial component, and that California gas will comprise a third smaller component. While the forecasts of TURN, CPG, and DRA were all lower than PG&E's forecast, the percentage difference is fairly small. The difference between the highest forecast (PG&E) and the lowest (DRA) is less than 7%.

Thus the stipulating parties urge that adoption of $2.23 per Dth, which is within 4% of each of their original forecasts, is a reasonable approach for the Commission to take.

3) Discussion

We agree with the stipulating parties that their core WACOG of $2.23 per Dth is a reasonable compromise of their original positions. We note that no party in its briefs contested this number. With only a 7% differential between the highest and lowest forecast, the stipulating parties wisely chose a compromise figure that is reasonable and will be adopted in this proceeding.

b. Non-Core WACOG

1) Original Positions of Parties

The non-core portfolio consists of short-term gas purchases from the U.S. Southwest over El Paso's Pipeline System. DRA and PG&E used separate methods to forecast the non-core WACOG, but arrived at very similar results.

PG&E forecasts mainline cost into the El Paso Pipeline System and then adds expected transportation rates over El Paso Pipeline to the California border. This results in a non-core WACOG price of $2.52 per Dth. By contrast, DRA forecasts the price of gas at the California border. DRA's non-core WACOG figure is $2.53 per Dth.

2) Stipulation Position

The stipulation selects the non-core WACOG to be $2.52 per Dth for the ACAP test period.

3) Discussion

With only a penny per Decatherm in dispute between DRA and PG&E we see no reason to do anything other than adopt the stipulation figure of $2.52 per Dth for the noncore WACOG. We are pleased that the parties wisely did not choose to litigate this minuscule difference.

3. Gas Throughput Forecast

Gas throughput is a measure of the total amount of natural gas supplied during the ACAP period. Throughput estimates are a key factor used in allocating cost among the various classes of customers, thus having a direct effect on rates. It reflects forecast gas demand, forecast gas supply, and any curtailments forecast during the ACAP period as a result of gas supply or system capacity constraints. Reasonably accurate throughput estimates are important in order to fairly allocate costs among customers, and to provide the utility with fair opportunity to earn its authorized rate of return.

a. Non-core throughput

PG&E's non-core throughput consists of Natural Gas supplied for industrial, cogeneration, Enhanced Oil Recovery (EOR), Wholesale, SCE Cool Water, Steam Heat, Interdepartmental, and PG&E UEG uses.

1) Industrial Throughput

Industrial throughput consists of three components: 1) throughput forecast on rate schedule G-P2B; 2) throughput forecast on rate schedule G-IND, excluding SCE Cool Water throughput, steam heat, interdepartmental and industrial GC-2; 3) throughput industrial customers on GC-2 contract.

PG&E originally forecasted 16.8 MMDth of G-P2B throughput, 129.1 MMDth of G-IND throughput and 9.1 MMDth of industrial GC-2 throughput. In each of these forecasts, PG&E assumed a slight amount of curtailment. In contrast, DRA, did not forecast any curtailment of the customers. DRA's original forecast is: 21.3 MMDth for G-P2B throughput, 169.4 MMDth for G-IND throughput and 9.1 MMDth for GC-2 throughput.

The stipulating parties compromised on their original position and agreed on the following forecast: 17.5 MMDth of G-P2B throughput, 138.3 MMDth of G-IND throughput, and 9.1 MMDth of Industrial GC-2 throughput. The G-P2B and G-IND throughput forecast represent a 3 percent increase from PG&E's original numbers. Since both DRA and PG&E agreed on the Industrial GC-2 throughput number of 9.1 MMDth, it was adopted in the stipulation.

2) SCE Cool Water Throughput

PG&E and DRA both originally forecast SCE Cool Water throughput at 17.8 MMDth. This is in spite of the fact that PG&E forecasts some curtailment at Cool Water, while DRA did not forecast any Cool Water curtailments. TURN's original forecast for Cool Water throughput was 24.9 MMDth. SCE urged that whatever throughput forecast was adopted in the SoCal Gas ACAP should also be adopted in this proceeding. All of these parties agreed in the stipulation to 23.9 MMDth. This stipulation forecast is derived from the 1990 California Gas Report in conjunction with the Cool Water forecast incorporated into SCE's September 1990 ECAC settlement agreement.

3) Cogeneration Throughput

PG&E and DRA fundamentally agreed on the cogeneration throughput forecast, despite the fact that PG&E had forecast a slight amount of curtailment to these customers in its original filing. The stipulation's cogeneration forecast incorporated PG&E's forecast of demand on rate schedule G-COG at 63 MMDth and the cogeneration throughput forecast of 6.6 MMDth for cogeneration customers served under GC-2 contracts. No other party challenged these numbers.

(4) **Industrial, Interdepartmental, Steam Heat and EOR Throughput**

Once again PG&E and DRA had virtually the same forecast for these categories. Only for EOR throughput was there a slight difference between PG&E and DRA's forecast. This difference occurred because PG&E forecasted slightly more curtailment in that category. The stipulated forecast for these categories are: .1 MMDth for Industrial Interdepartmental, 1.1 MMDth for Steam Heat throughput, and 50.6 MMDth for EOR throughput. No other party forecast throughput for any of these categories.

5) UEG Throughput

PG&E and DRA were the only two parties to forecast UEG throughput, both agreeing on a 164.4 MMDth forecast of UEG demand. However, PG&E and DRA disagreed slightly regarding UEG curtailments. PG&E originally forecast UEG curtailments of 21.4 MMDth while DRA originally forecast UEG curtailment of 13.9 MMDth. The stipulating parties adopted a UEG throughput forecast of 146.3 MMDth. This throughput forecast assumes a level of curtailment of 18.2 MMDth, a compromise between the positions of DRA and PG&E in their original testimony. Once again, no other party commented on these figures.

6) Curtailments

There was more of a variety regarding curtailment estimates by the active parties. PG&E forecasts 29.7 MMDth of curtailment occurring in several non-core classes. DRA forecasts 13.9 MMDth of curtailments all in Priority P5, which consists of UEG and EOR customers. TURN suggests that curtailments should be approximately 10MMDth less than what was forecasted by PG&E. The stipulating parties adopted a level of curtailment of 20 MMDth, all occurring in Priority P-5. This number is very similar to the figure originally recommended by TURN and falls between the original positions of PG&E and DRA. Further, the stipulation number is reasonable because it assumes that all curtailment is limited to customers in the lowest priority class, P-5. No other party disputed this figure in the stipulation.

7) Wholesale Throughput

There was no dispute among any parties in their original testimony as to PG&E's original forecast of 13.7 MMDth for wholesale throughput. Therefore this figure was incorporated in the stipulation.

8) <u>Discussion</u>

The stipulation non-core throughput figures are a reasonable compromise in the cases where there was any disagreement among the parties in their original testimony. For the most part these numbers were nearly the same. Therefore we will adopt the non-core throughput forecast as set forth in the stipulation. By adopting these non-core throughput numbers we give them no precedential significance for future proceedings before the Commission. We agree that the parties, where there was disagreement, reached reasonable compromises given their overall desire to settle this proceeding.

b. <u>Core Throughput</u>

1) <u>Residential and Commercial Throughput</u>

PG&E's and DRA's forecast of throughput for residential and commercial customers were practically identical in their original filings. For residential throughput PG&E originally forecasted 217.2 MMDth while DRA forecasted 210.7 MMDth. As for commercial throughput, PG&E forecasted 90.6 MMDth while DRA forecasted 91.1 MMDth. The stipulating parties adopted PG&E's original positions. The stipulation residential throughput forecast, therefore, is 217.2 MMDth and its commercial throughput forecast is 90.6 MMDth.

2) <u>Core Interdepartmental and PG&E UEG Startup Fuel Throughput</u>

In their original testimony, PG&E and DRA agreed on the numbers for these relatively small throughput items. The stipulation adopted the agreed-upon numbers as follows: .2 MMDth for core interdepartmental and 1.4 MMDth for PG&E UEG startup fuel.

3) <u>Discussion</u>

Given the lack of controversy over all the core throughput numbers both in original testimony and in the stipulation, we will adopt the stipulation forecast as described above. To do otherwise would create controversy were there is none.

c. Shrinkage

This category is made up of forecasts for PG&E's own gas department use and lost and unaccounted for usage (LAUF). DRA accepted PG&E's forecast for these categories in its original testimony. Thus the stipulation forecast incorporates the same numbers that were in PG&E's original forecast. The stipulation assumes a forecast of 8.2 MMDth for gas department use and 17.5 MMDth for LAUF. Given that there is no dispute over these numbers we find them to be reasonable and adopt them.

d. Cold Year Throughput

The cold year throughput forecast is used in the cost allocation and rate design process. This forecast for any two classes can differ for two reasons. First, the demand may change from average year to cold year conditions and second, curtailment levels affecting the class might change from average year to cold year conditions. Changes in demand are anticipated primarily from core residential and commercial customers. Therefore different demands are developed for these customer classes. Recognizing that a substantial component of the wholesale load consists of residential customers, TURN proposed that a separate cold year wholesale forecast should be developed. Finally, Steam Heat demand increases slightly in cold years. Except for the wholesale figure, the increased cold year demand for the other categories as set forth in the stipulation tables (see Appendix D) were not disputed.

1) Cold Year Wholesale Throughput

DRA and PG&E originally forecasted that wholesale throughput would be the same in a cold year as in an average year. TURN, on the other hand, forecasted an increase of 12 percent over average year conditions. In the stipulation, the parties compromise on their positions and predicted an increase of six percent over average year forecast, resulting in a cold year throughput forecast for wholesale customers of 14.6 MMDth. The stipulation places the additional throughput in the winter months.

2) Cold Year Curtailments

In its original testimony PG&E forecasted 47 MMDth of curtailments in a cold year occurring for several customer classes. TURN recommended that PG&E's forecast be lowered by approximately 10 MMDth. Meanwhile, DRA suggested a forecast of 40 MMDth of curtailments in a cold year, all occurring in Priority P-5.

Once again, the stipulation reached the compromise between the parties original positions and incorporates 37 MMDth of curtailments in a cold year, all placed in Priority P-5.

3) Discussion

As to the cold year throughput numbers to which there was no disagreement, we will adopt the numbers set forth in the stipulation and find they are reasonable. We agree with the stipulation's acceptance of TURN's argument that because a significant component of wholesale customers' demand is residential and commercial, an adjustment needs to be made in a cold year. Therefore, the 6 percent increase in the cold year wholesale throughput forecast is reasonable. Likewise, the forecast cold year curtailment of 37 MMDth incorporated in the stipulation is a reasonable number representing, once again, a compromise between the positions of PG&E, TURN, and DRA in their original testimony. We will adopt all the cold year throughput numbers as set forth in the stipulation.

c. Interutility Throughput and Rates

Traditionally, in an ACAP proceeding, this is a controversial throughput figure. Usually, there is a wide spectrum of opinions regarding the amount of interutility throughput expected to occur during the test period. Unlike other throughput estimates discussed earlier, the parties originally forecasted a wider range of interutility throughput. PG&E originally forecast

27.5 MMDth of interutility throughput, DRA forecasted 53 MMDth, while TURN came in with the highest number, forecasting 70 MMDth.

The stipulating parties reached a compromise on their original positions agreeing to an interutility throughput forecast of 50 MMDth, 3.9 MMDth originating from California sources and 46.1 MMDth occurring from Topock to Kern River.

Additionally the stipulating parties agreed to an additional 2.1 cents per Dth to be incorporated into the forecast interutility rate to reflect an increase in interutility transport rates to collect gas gathering costs. The stipulating parties agreed that this 2.1 cents per Dth is necessary in order to comply with D.89-12-016, which ordered natural gas utilities to incorporate into the interutility rate a component representing gas gathering costs.

We will adopt the stipulation position on interutility throughput. Since this is always a controversial issue in ACAP proceedings, selecting an interutility throughput number which is a compromise of all the parties' original estimates is a reasonable approach and will be adopted.

4. Revenue Requirement

a. Overview

The total revenue requirement is the amount which PG&E requests to be recovered from customers during the ACAP period. This includes both the revenue requirement related to gas procurement and the revenue requirement related to all other costs, which are recovered through transportation rates. The revenue requirement includes test year expenses such as pipeline demand charges, account balances such as the core gas fixed cost account, and revenue credits such as the interutility revenue credit. The complete list of these different line items is much longer. For the most part the stipulating parties relied on the determination of the revenue requirement as set forth in PG&E's prepared testimony (Exhibit 1, Chapter 5). Therefore there is no need in the text of this decision to describe the various credits and balancing accounts that are uncontroversial in this proceeding. They will be listed in the tables attached to this decision. (See Appendix C.)

The only difference between the stipulation's treatment of PG&E's revenue requirement and that in PG&E's prepared testimony concern the following:

1. The 90 percent balancing account (this will be discussed in a later section since it is a contested element of stipulation).

2. The EOR, NRSA and CFA Account Balances.

3. The PGT Refund, which is returned through core gas fixed cost account and the non-core pipeline demand charge trueup.

4. The direct billed take or pay amount (likewise this item will be discussed in a later section since it is a contested element of stipulation).

5. The return to ratepayers of the balance in the NGV Memorandum Account.

Other revenue requirements items that are worthy of discussion in the text of the decision are the RD&D Credit, PG&E's proposal to consolidate several balancing accounts, and the brokerage fees.

The update exhibit, submitted on February 19, 1991, which includes January 31, 1991, balancing account amounts, has been prepared in compliance with the terms of the stipulation according to PG&E. This update indicates a net rate decrease (as compared to present January 1, 1991 rates) of approximately $47,811,000 to PG&E. Overall this is a 2.1 percent decrease in revenue requirement. However, there will be a 1.2 percent increase in residential rates or $15,105,000. For the total core there is .3 percent revenue requirement decrease. The total non-core revenue requirement decrease is 9.2 percent. Parties were allowed to comment on the update exhibit at the same time they commented on the ALJ draft decision in this proceeding.

b. EOR, NSRA and CFA Account Balance Adjustments

The stipulating parties agreed that the EOR, NRSA and CFA Balancing Account balances should be adjusted to reflect the recommendations of the DRA audit of these accounts as described in DRA's prepared testimony (Exhibit 9). No other party to the proceeding took issue with these recommendations.

The stipulation recommends that the balance in the allowance for doubtful accounts within the CFA debt service account be lowered to 5.4 percent of the outstanding loan portfolio balance as of the effective date of this decision. The stipulation recommends that the NSRA balance be decreased by $4.535 million. Finally, the stipulation recommends that the amount in the EOR balancing account be decreased by $319,222. We will adopt these three balancing account adjustments since they are the result of a DRA audit and were not opposed by any party. We order that these adjustments be reflected in the rate tables attached to this decision.

c. PGT Refund

The stipulation recommends that the estimate of the PGT refund be updated to $6.8 million to reflect the amount actually received by PG&E. In the update exhibit, these adjustments have been made to the core fixed costs account and to the pipeline demand charge true up amount as directed by the stipulation. No other party has presented testimony opposing this proposal. Therefore we will adopt the proposal as set forth in this stipulation and set forth in the update exhibit.

d. NGV Memorandum Account

The stipulation suggests that the balance in the natural gas vehicle (NGV) memorandum account should not be included in the revenue requirement for this year's ACAP. The stipulation proposes that the amount remain in the memorandum account to be allocated in PG&E's next cost allocation proceeding.

We will adopt this recommendation, agreeing with the parties that it is appropriate to postpone this account's allocation in light of the fact that a decision on PG&E's NGV program has not yet been issued.

e. RD&D Adjustment

The parties suggested different treatment of the Research Development and Demonstration (RD&D) adjustment. TURN in its prepared testimony proposed a different allocation of the RD&D adjustment between core and non-core than that proposed by PG&E. Specifically, TURN proposed to allocate $668,000 of the RD&D adjustment to the core and $412,000 to the non-core. DRA proposed that the RD&D adjustment should be allocated based on cold year peak season throughput. DRA then proposed in its rebuttal testimony the position ultimately adopted by the stipulating parties. The stipulation recommends that the total RD&D adjustment of $1.008 million be allocated as follows: $728,000 to the core and $352,000 to the non-core. The stipulation further recommends that the Core Gas Fixed Account balance and the NRSA balance, respectively, be changed to reflect the RD&D amounts.

Once again, since no other parties suggest any other treatment of the RD&D adjustment we will adopt the proposal by the stipulating parties.

f. Consolidation of Balancing Accounts

The stipulation adopts PG&E's proposal set forth in its original prepared testimony to consolidate several balancing accounts. The proposal would:

1. Eliminate the Core/Core-Elect Surcharge Subaccount of the Core Purchased Gas Account by allocating the remaining balance between the Core Subaccount and the Core-Elect Subaccount,

2. Eliminate the Core Implementation Balancing Account by transferring the remaining balance to the Core Gas Fixed Cost Account,

3. Eliminate the Noncore Implementation Account and the Negotiated Revenue Stability Account by transferring the remaining balances to the Noncore Transition Cost Account.

No party disagreed with any of these recommendations and we will follow the lead of the parties and adopt the proposals as set forth.

g. Brokerage Fees

The stipulating parties have agreed to two possible amounts for the brokerage fee to be included in the procurement revenue requirement (and credited against the transportation revenue requirement). PG&E had been ordered to file a detailed study of brokerage costs in this year's ACAP proceeding pursuant to D.88-09-032 (Ordering Paragraph 5). However the study was still being prepared by its consultant, Price Waterhouse, at the time PG&E filed its application in this proceeding. At the close of hearings on November 29, 1990, the gas brokerage cost study had not yet been filed. Therefore, the ALJ submitted as Phase 1, the traditional ACAP issues just completed, reserving a potential Phase 2 on the gas brokerage cost study depending on the parties' reactions to it. PG&E filed its gas brokerage cost study as promised on December 17, 1990. The ALJ had instructed parties to state their position on the gas brokerage cost study in their opening briefs to this proceeding.[2] The Price Waterhouse Study recommends a gas brokerage fee of $6,637,163. At least one party requested a PHC for a potential Phase 2 of this proceeding. The

2 CPG specifically argued against any hearings being convened on the study and urged use of the study's result in the Rate Tables for this decision.

first PHC on that topic was held on February 1, 1991. A discovery schedule was set, and a second PHC was held March 22, 1991. Hearings are scheduled for May 1991. The parties agreed if the Price Waterhouse study figure was questioned, then the update exhibit would use the $11.124 million figure escalated by appropriate factors set forth in the January 1, 1991, attrition decision. Therefore the update exhibit (Exhibit 28) shows the brokerage fee credit at $11,810,000. Since at the time of writing this decision it is unknown what the final number will be, we will order that $11,810,000 figure be used in the rate tables attached to this decision. As suggested by PG&E in its comments on the proposed decision, we shall make this brokerage fee revenue requirement subject to balancing account treatment for the current ACAP period since the outcome of Phase 2 is unknown at this time.

5. <u>Discounting</u>

a. <u>Overview</u>

Traditionally in ACAP proceedings, what has become known as the discount adjustment calculation has been a controversial issue. Discounting is a critical factor in the Commission's current gas industry structure. The Commission has authorized gas utilities to discount rates in order to increase the sales volume over which the utilities fixed costs are spread. This discount adjustment is a mechanism used to adjust the non-core revenue estimate to reflect the amount of incremental, or additional, revenue a utility can earn from non-core industrial sales through discounting. This discounting is necessary in order to make the price for natural gas service competitive with that of the customer's alternative fuel. The discount adjustment mechanism, usually debated in ACAP proceedings, allows PG&E an opportunity to recover its authorized revenue requirement by reallocating the incremental revenue difference to other customers. If these adjustments were not done, it would result in more costs being allocated to customers capable of switching to other fuels than could be recovered in rates.

The reality that discounting usually occurs for large industrial customers complicates cost allocation. In order to properly allocate costs it is necessary to estimate the expected level of discounting that will occur during the ACAP period. The expected level of discounting drives the forecast for the amount of revenue that can be collected from non-core customers, and thus the amount of revenues which need to be collected from the remaining customers in order to obtain total revenue requirement.

In their original filings, the parties proposed substantially different approaches for estimating the transportation revenues anticipated to be collected from non-core customers. Thankfully, it is not necessary to go into detail on the different methodologies that PG&E, TURN, and DRA originally proposed. The stipulating parties have agreed that only minimum discounting would occur because of their assumption that oil prices will be high enough relative to the commodity cost of gas during the test period. Since no other party has disputed the amount of discounting the stipulation assumes we see no reason to take the time to explain and describe the original discount adjustment mechanisms proposed by the parties.

b. Discounting to Rate Schedules G-IND (Excluding SCE Cool Water), G-P2B and G-COG

As has been emphasized, the stipulation does not recommend that any specific oil price be adopted. Instead, the stipulating parties recognized an implicit assumption that oil prices will be high enough so that only minimum discounting would be required during the test period. Specifically, the stipulation puts forward the following discount factors: Rate schedule G-IND excluding Cool Water 98 percent; rate schedule G-P2B, 97 percent; and rate schedule G-COG, 99 percent. All the discounting models originally proposed are driven primarily by anticipated differences in the prices of crude oil and natural gas. All the models showed that at relatively high crude oil prices there would be a relatively low level of discounting.

PG&E contends that the level of discounting adopted by the stipulation is very conservative, far less than has occurred historically since the restructuring of the natural gas industry in May, 1988. PG&E and the other stipulating parties urged that these conservative numbers be adopted in light of circumstances surrounding this ACAP. PG&E, however, points out that if oil prices dropped dramatically the required discounting will increase substantially thereby reducing the revenues PG&E will be able to recover from the noncore. Further, PG&E alleges that if oil prices rise higher than they are currently, PG&E could not increase the revenues it recovers from non-core customers for transportation service. For this reason, PG&E argues that the adoption of this conservative estimate of discounting can not be separated from the adoption of the 90 percent balancing account for non-core revenues. (The 90 percent balancing account issue will be discussed in a later section.)

We will adopt the stipulation discounting percentages for each of the above classes. We find this to be a reasonable approach in light of the continuing uncertainties regarding oil prices as a result of the Gulf war.

c. <u>SCE Cool Water Revenues</u>

PG&E serves SCE's Cool Water Plant located near Barstow, California. We have previously discussed the throughput estimates for the SCE Cool Water Plant in section 3.a(2). Here we discuss the projected revenues from SCE Cool Water based on that total forecast of 23.9 MMDth of throughput. The parties originally disagreed as to how this throughput should be priced. The stipulation ultimately adopted the recommendation of SCE. The pricing finally agreed upon in the stipulation, consistent with

SCE's proposal, recognizes that some volumes at Cool Water will be served at the higher rate, i.e., the G-IND standard service rate, while the bulk of the throughput will occur at a price which is competitive with the alternative fuel price at SCE Cool Water, or SoCalGas' Tier 2 UEG rate. Thus, out of the 23.9 MMDth of throughput only 6 MMDth will be assumed to be priced at PG&E's G-IND standard service rate with the remaining 17.9 MMDth priced at 29.15 cents per Dth (which is the SoCalGas Tier 2 UEG rate adopted in D.90-11-023, SoCalGas' most recent ACAP decision).

We concur with the stipulation pricing for the Cool Water facility since it reflects the market reality associated with this plant. We will adopt these revenue estimates as reasonable.

6. Cost Allocation

While cost allocation is what an ACAP proceeding is all about, not much time will be devoted to the subject in this decision because of the stipulation reached by the parties. However, we will briefly describe what cost allocation is. Cost allocation involves the assignment of the authorized costs associated with the operation of the utility system to the various customer classes for recovery through rates. The costs to be allocated generally fall into two categories: variable cost and fixed cost. The principal variable cost, and usually the subject of much debate in an ACAP, is the cost of gas purchased by the utility. It is a variable cost because the total expense to the utility varies with the price of gas and the amount of gas sold. The allocation of the commodity cost of gas is straightforward. Customers are charged for the gas that they used on a cents per therm basis. Since the utility is required to sell the gas it purchases at cost, the core and non-core WACOG adopted in the ACAP are based exclusively on the estimate of what gas will cost the utility during the forecast period. Any over- and undercollection of core gas costs are captured in a balancing account and amortized in the next forecast period.

Fixed costs are relatively stable. They tend to be independent of the amount of gas flowing through the utility system. The largest fixed cost which must be allocated is the base revenue requirement adopted in the utility's most recent general rate case.

The total base revenue requirement is first broken up into functional components which correspond to different aspects of the utility's operations. The five functional categories are production, storage, distribution, transmission, and general categories. Each of these categories of expenses is then classified into customer commodity and demand components. Various allocation factors, based on either weighted customer or various throughput based allocators, are then applied to the classified base revenues to allocate them to the customer classes.

Specifically, costs are allocated to residential, small commercial, large commercial, industrial P2B/IND, Utility Electric Generation (UEG), Cogeneration, and Wholesale Customer categories. Enhanced Oil Recovery (EOR) customers are not allocated costs. Rather, the revenues received from this customer class are treated as incremental and allocated as revenue credits to the other classes.

After the costs have been functionalized, classified, and allocated, rates are set to recover them. Costs are recovered in rates through either customer charges, demand charges, or volumetric charges. As a general rule, costs that were classified as customer-related are recovered through the customer charge. For non-core customers, costs that were classified as demand-related are recovered through demand charges; while commodity-related costs are recovered in the volumetric charge.

Except as expressly noted in the stipulation, the stipulation recommends that the Commission adopt the cost allocation methods set forth in PG&E's prepared testimony. The allocation of the NGV credit has already been discussed in an earlier section of this decision where we agreed with the stipulating parties to postpone the allocation of this credit until the next cost allocation proceeding. The only other contested cost allocation issue relates to the allocation of revenue from long-term contracts. This was not an element of the stipulation since the parties could not reach agreement on this point and will be discussed later in this decision.

Since no party has objected, we will adopt the stipulated cost allocation as set forth in Exhibit 27 as reasonable.

7. Rate Design

a. Core Rates

In the original testimony of the parties, only two issues arose with regard to core rate design: the level of residential Tier differential reduction and the calculation of the LIRA (Low Income Ratepayer Assistance) credit. Other than these two issues, all the parties agreed on rate design methodologies for core rates, which are in accordance with previously adopted Commission methods. The stipulating parties state that the rates set forth in their stipulation follow those same methods.

The stipulation provides that the tier differential, measured by the ratio of Tier II rates to Tier I rates, should be reduced by maintaining the difference between the tiers in absolute terms. In fact this was PG&E's original proposal. TURN supported PG&E's proposal. DRA originally recommended a 15 percent tier differential reduction unless PG&E's revenue requirement were adopted. In that event DRA proposed that PG&E's tier differential reduction approach be adopted. We concur that stipulation proposal is a reasonable one to reduce the residential tier differential because it reflects the consensus of the parties and therefore should be adopted.

PG&E recommended a change in the calculation of the LIRA credit from what was used last year. No party challenged PG&E's new approach. PG&E's proposal has been incorporated into the stipulation. The stipulating parties recommend that LIRA volumes and revenues be fully credited to the core revenue requirement before allocating costs among non-LIRA residential and commercial classes. In this way, the average core commercial rate will be equal to the average residential non-LIRA rate. We agree with the stipulating parties that this proposal is a reasonable one and it shall be adopted.

b. Natural Gas Vehicle Rates

PG&E proposed to maintain the natural gas vehicle rates as experimental rates to which no costs are allocated. The stipulation adopted this proposal. The stipulation does not addressed NGV rates explicitly. Thus, it implicitly incorporates PG&E's proposal. Revenues from the NGV rate schedules are collected in a memorandum account to be allocated back to ratepayers as a revenue credit. As we stated earlier, this issue will be decided in PG&E's next cost allocation proceeding.

c. Noncore Rate

The parties to the stipulation intentionally did not address the one contested non-core rate design issue. That issue, whether cogeneration rates should be established on a forecast basis, will be discussed in a later section.

Except for that cogeneration issue, PG&E's rate design methodology for non-core rates was not challenged by any other party. The methods that PG&E used are consistent with those that have been adopted by prior Commission decisions and their use should be continued in this ACAP. We see no reason to do anything different than what has been done by PG&E as to these uncontroversial and uncontested rate design issues.

B. Contested Elements of Stipulation

1. Direct-Billed Take-or Pay Costs

a. Overview

The issue of what to do about direct-billed take-or-pay (TOP) costs is one thrust upon the Commission by a series of

Federal Energy Regulatory Commission (FERC) actions. Briefly, direct-billed TOP costs are amounts billed to PG&E by El Paso Natural Gas Company (El Paso) to recover payments made to gas producers as consideration for waiving, revising, or amending the take-or-pay minimum payment provisions of a contract. These take-or-pay costs result from contracts between pipelines and producers. Neither PG&E nor any of its customers were parties to those contracts.

Most recently in its series of TOP related cases, the FERC issued Order 528 (53 FERC ¶61,163). In Order 528, the FERC stayed the tariff provisions of pipeline companies which provide for assessment of fixed charges or direct bills to recover TOP settlement costs on the basis of a purchase deficiency allocation method. New tariffs were ordered to be filed.

Currently, El Paso's pipeline charges are based on a purchase deficiency allocation method. On November 7, 1990, El Paso filed a motion at the FERC requesting inclusion in the category of pipelines that are not subject to the stay, or in the alternative, for deferral of the stay (53 FERC ¶61,348). The FERC deferred application of the stay to El Paso's existing deficiency-based fixed TOP charges until 30 days after the FERC issues an order on the El Paso Rate Case settlement. The FERC stated that "El Paso's collection of these costs is subject to refund." (53 FERC ¶61,348, p. 7.)

On November 16, 1990, El Paso filed primary and alternate tariff sheets updating its monthly fixed TOP charges and volumetric surcharge of TOP costs. This update had the effect of increasing the TOP cost. However, FERC rejected the primary tariff sheets because they were based on the purchase deficiency allocation method which was found unlawful in <u>Associated Gas Distributors vs. FERC.</u> (D.C. Cir. (1989) 893 F. 2d 349). The FERC did accept the alternate tariff sheets (which are based on the percentages in El

Paso's pending global settlement offer) and suspended them for five months to become effective May 17, 1991. (53 FERC ¶61,373.)

Against this background of swirling changes at FERC, it is understandable why TOP costs are a contested issue in this proceeding. The debate for the purposes of this decision is to determine what is the appropriate amount to assume in the revenue requirement as take-or-pay costs to be borne by PG&E will have to pay during this ACAP test period. It is important to note that we already have a mechanism in place called the take-or-pay true up to capture any errors in the forecast of the take-or-pay costs in the next cost allocation proceeding. The stipulating parties recommend TOP costs of $27.5 million. Salmon Resources Ltd. (Salmon) believes it would be more appropriate to assume TOP costs of $53.3 million. This is the only element of the stipulation that Salmon opposes. The arguments in support of their positions will be discussed below.

b. <u>Stipulating Parties Position</u>

In their original testimony, both PG&E and DRA has estimated TOP costs of around $50 million. The Stipulating parties propose a $27.5 million forecast of TOP costs to be incurred by PG&E during the test period. While not signing the stipulation, California Industrial Group, California Manufacturers Association and California League of Food Processors (CIG, et. al.) join in support of the $27.5 million forecast.

On November 13, 1990, prior to reaching agreement on this figure, TURN and CIG et al. filed a Joint Motion to Suspend the Collection of Direct-Billed Take-or-Pay Costs (Joint Motion) in this docket, last year's PG&E ACAP docket and SoCalGas' 1989 - 1990 ACAP proceeding. The Joint Motion argues that in light of recent FERC and US Court of Appeals actions, suspending collection by PG&E of TOP costs is the best way to protect California ratepayers against overcharges. Specifically, the Joint Motion refers to the United States Court of Appeals for the District of Columbia Circuit decision which invalidated the FERC's Order 500 purchased gas deficiency methodology on the grounds that it violated the filed rate doctrine and the rule against retroactive ratemaking. (Associated Gas Distributors vs. FERC, 893 F. 2d 349, D.C. Circuit 1989). On October 9, 1990, the United States Supreme Court denied a petition for writ of certiorari filed on FERC's behalf. (FERC vs. Associated Gas Distributors, 59 U.S.L.W. 3271, October 9, 1990.)

On November 1, 1990, FERC responded to these decisions by issuing Order 528, which stayed the collection of direct-billed TOP costs by 13 primary pipelines, including El Paso and Transwestern, effective 30 days from the date of publication of Order 528 in the Federal Register.

The Joint Motion goes on to describe that El Paso filed a motion before FERC on November 7, 1990, for modification of Order 528 or, in the alternative, a motion for stay of its application to El Paso. At the time of the filing of the Joint Motion, FERC had not yet acted on El Paso's motion. Therefore, TURN and CIG et al. argued for suspension of collection of TOP costs pursuant to Order 528.

However, as discussed above, FERC has issued an order accepting (but suspending until May 17, 1991) El Paso's alternate tariff sheets which allocate TOP costs among individual sales customers based on percentages reflected in El Paso's pending rate case settlement.

In any event, TURN and CIG et al. withdrew their Joint Motion as to this application and last year's PG&E ACAP on November 26, 1990 agreeing to the $27.5 million in the Stipulation for TOP costs.

The stipulating parties, particularly PG&E, TURN, and DRA all said in their briefs that they intended to confer prior to the update exhibit's filing as to whether the $27.5 million figure should be changed. The update exhibit addresses this issue.

stating: "After consultation with DRA, CIG, and TURN, PG&E believes that the original estimate of direct-billed take-or-pay costs of $27.5 million remains a reasonable estimate of expected costs." (Exhibit 28, p. 1-1.)

The update exhibit offers no further justification of the stipulating parties for the $27.5 million figure. Therefore, we will turn to the testimony given by the panel members in support of the stipulation for their rationale.

PG&E witness Smith testified that there are a number of issues in the proposed El Paso rate case settlement that would both increase and decrease the direct billed portion of the El Paso TOP costs for which PG&E is responsible. He did not know whether there is a likelihood that actual TOP costs are going to be greater than $27.5 million. (Tr. Vol. 6, p. 368.) PG&E witness Frank had earlier testified that she thought TOP costs would be about $41.3 million to $43.9 million if the El Paso settlement is adopted. However, the Stipulating parties made no explicit assumptions regarding the outcome of the El Paso settlement. The stipulation supports the $27.5 million figure as set forth in the update exhibit. If the actual TOP costs are greater or less than the $27.5 million, the TOP true up account will correct the difference in the next forecast proceeding.

c. <u>Salmon Resources Ltd.'s Position</u>

Salmon disagrees with the stipulating parties' selection of $27.5 million as an appropriate TOP cost forecast. Salmon argues that the forecast should be at or near $50.3 million in light of FERC actions after the close of hearing. Salmon argues that the uncertainty that existed regarding suspension of TOP costs at the time the stipulation was executed has largely been eliminated due to the two orders issued by FERC in December 1990 (and discussed earlier in this decision).

Salmon argues that FERC's December 7, 1990 order (53 F.E.R.C.¶61,348) defers the applicability of Order 528 to El Paso, allowing El Paso to continue to assess TOP costs directly to its firm sales customers, including PG&E, until after the FERC rules on its rate case settlement. Salmon contends that the uncertainty regarding whether El Paso may continue to bill its customers for TOP costs has largely been eliminated. Salmon argues that since there now is no reason to assume that El Paso will be prevented from billing PG&E for TOP costs, the $27.5 million figure is too low.

Salmon cites FERC's second December order, issued December 14, 1990, for additional justification for increasing the TOP forecast (53 F.E.R.C. ¶61,373 (1990)). This order addressed El Paso's November 16, 1990, application to increase the level of its direct-billed TOP costs to reflect approximately $60 million in additional TOP buy-out costs.

On cross-examination by counsel for Salmon, PG&E's witness Frank testified that if El Paso were exempted from Order 528 and its November request for a TOP increase were approved, the TOP forecast should be $53.3 million during the forecast period. Alternatively, she testified that if El Paso's rate case settlement, which incorporates the new allocation of direct-billed TOP costs, and the November increase were both approved, her forecast for PG&E TOP costs during the ACAP period would be $43.9 million (Tr. Vol. 5, pp. 297-98).

Salmon argues that FERC's approval, despite suspension of the "alternative" tariff sheets filed November 16, 1990, will result in an increase in El Paso's direct-billed TOP costs, going into effect on May 17, 1991. Salmon believes the forecast for TOP costs adopted in this proceeding should incorporate the FERC approved increase.

Salmon submits that the TOP forecast for this ACAP period should be at least between $43.9 million and $53.3 million. Salmon contends that the uncertainty over the amount of the TOP costs is now based primarily upon the "timing" of FERC action on the El Paso rate case settlement. Salmon cites the December 7, 1990 FERC order as stating that it intended to consider the El Paso settlement within the next three months (53 F.E.R.C. ¶61,348, p. 6). Salmon alleges that if FERC rules upon El Paso's settlement in that time period, the TOP costs forecast should be closer to $43.9 million.

On the other hand, Salmon contends that if a FERC ruling is delayed until later in the ACAP test period, the forecast of direct-billed TOP costs should be closer to the $53.3 million figure.

Salmon points to testimony of stipulation panel member Smith as stating that PG&E would update the TOP costs "if Order 528 was resolved or if El Paso was not governed by that stay" (Tr. Vol. 6, p. 393). Salmon concludes that in light of these December FERC orders, an update increasing TOP costs is appropriate.

Finally, Salmon argues it is better to increase the TOP cost forecast now than rely on the "true up" mechanism in a future cost allocation proceeding. Too low a forecast, resulting in a shortfall that must be "trued up" in some later period, only prolongs these TOP "transition costs." Salmon quotes D.87-12-039:

> "Clearly, at some point, after pipelines have had a reasonable time to reform their old contracts to conform to competitive markets, transition treatment of take-or-pay costs must end." (D.87-12-039, mimeo. p. 35.)

Salmon argues that understating TOP costs, as proposed by the Stipulation, presents the potential for perpetuating the recovery of these transition costs beyond the end of the 1991-92 ACAP period. Salmon alleges that such an extension of this transition cost burden is not in the interest of ratepayers, suppliers or PG&E. Salmon urges the Commission to reject the $27.5 million stipulation figure as too low and seek as accurate as forecast of the TOP costs as is possible.

d. **Discussion**

Unfortunately, at the time of the testimony by the stipulation panel members supporting the $27.5 million figure we did not have the benefit of the two December FERC decisions. While our inclination is to support the stipulation number reached by a diverse group of parties, we are troubled by the arguments raised by Salmon. Moreover, none of the stipulating parties addressed the merits of Salmon's arguments, merely stating that the update exhibit will address the issue. However, the update exhibit merely stated that after consulting with the stipulating parties and CIG et al., PG&E believed the forecast should remain at $27.5 million.

We already have instituted a mechanism for all parties to comment on the update exhibit in their comments on the ALJ's proposed decision. We directed the stipulating parties to amplify their decision to leave the TOP costs forecast at $27.5 million in light of the FERC orders issued since the hearings in this proceeding concluded. The parties complied with this directive.

PG&E, DRA, and TURN all agree in their comments that the $27.5 million TOP forecast is still a reasonable estimate in light of yet another FERC order issued since the close of hearings. On March 20, 1991, FERC issued an Order Accepting in Part and Modifying in Part Amended Offer of Settlement (El Paso Settlement Order) (54 FERC ¶61,316). Under the provisions of this order, PG&E will incur approximately $42.9 million in direct billed TOP costs during the test period. However, this amount will be offset by a refund for a portion of the TOP costs incurred since December 1988. PG&E and DRA currently estimate this refund to be between $15-16 million. In light of this recent FERC action, the stipulating parties are even more confident that the $27.5 million figure is a reasonable one to use. We agree, particularly noting that the true up account will take care of any differences between the forecast and actual numbers. We note that Salmon did not address this issue at all in its comments, allowing us to infer that its objection to the 27.5 million figure has diminished.

We will adopt the $27.5 million figure set forth in the stipulation.

2. **90% Balancing Account for NonCore Transportation Revenues**

a. Overview

The stipulating parties agreed on 90 percent balancing account treatment for noncore transportation revenues to be in effect during the entire ACAP forecast period, i.e. through March 31, 1992. Meanwhile, D.90-09-089 set up a system due to commence August 1, 1991 incorporating a 75 percent balancing account scheme for noncore revenues. Only CIG et al. argue that the agreement reached by the stipulating parties should be altered to be consistent with D.90-09-089. The arguments of both the stipulating parties and CIG et al. are summarized below.

b. Stipulating Parties' Positions

PG&E, DRA, and TURN all stress in their briefs the importance of leaving the 90 percent balancing account intact as part of our approval of their stipulation.

The stipulation specifically calls for 90 percent of any variation between noncore transportation revenues, excluding those revenues amortizing balances in existing balancing accounts, and the adopted noncore revenue requirement, excluding balances of existing balancing accounts, be placed in an interest bearing balancing account. The stipulation provides that the allocation between classes of the balance in this account will be decided in PG&E's next cost allocation proceeding. The stipulation calls for the 90 percent balancing account to become effective on the date that the rate change resulting from this decision becomes effective. Further, it provides for the 90 percent balancing account to remain in effect until the implementation of rates resulting from PG&E's next cost allocation proceeding, currently estimated to be Spring 1992. (Exhibit 27, pp. 7-8.)

PG&E portrays the 90 percent balancing account provision as one of the key elements of developing a "win-win" settlement for all parties which was identified very early in the settlement discussions. PG&E points out that the stipulating parties agreed to a throughput forecast very similar to its own, but assumed that, with the exception of sales to SCE's Cool Water facility, there would be only minimal discounting of noncore transportation rates. PG&E asserts that agreement would have been impossible, given the disparate litigation positions and the uncertainties involved, without the 90 percent balancing account for noncore transportation revenues being incorporated into the Stipulation as a protection mechanism against forecasting uncertainties.

PG&E contends that the 90 percent balancing account is reasonable and necessary in light of the extreme uncertainty surrounding world oil markets caused by the Gulf War. PG&E points out that if the adopted crude oil price is higher than that which actually occurs during the test period, it will undercollect the revenue requirement allocated to noncore customers because it will have to discount transportation rates more than expected. PG&E states that under current regulation, PG&E shareholders will then experience losses due to events completely beyond PG&E's control.

On the other hand, PG&E argues that if actual oil prices are higher than those adopted in this case, it will collect almost no additional revenue because the Stipulation already assumes only minimal discounting. PG&E points out it cannot charge more than the standard service transportation rate no matter how high oil prices are.

In her supplemental testimony, PG&E witness McManus addressed the oil price uncertainty issue:

> "If the adopted oil prices are different than those that actually occur during the test period, shareholders and ratepayers experience,

under current regulation, gains or losses from events completely beyond their control.... The Commission should recognize that any forecast it may adopt MUST be based either explicitly or implicitly, on speculation regarding the events in the Middle East and that it is more than likely to be in error when viewed after the fact." (Exhibit 2, pp. 2-1, 2-2.)

It should be remembered that PG&E requested 100% balancing account treatment in its supplemental testimony (Exhibit 2). PG&E concludes that the negotiated compromise of a 90 percent balancing account allows protection for PG&E and its ratepayers in the event that PG&E under- or overcollects from noncore transportation customers.

Both DRA and TURN, representatives of California ratepayers, support the 90 percent balancing account as necessary element of the overall stipulation. Both parties argue that given the evidence in this case, the uncertain oil market, and the joint desire of PG&E, TURN and DRA to resolve the issues in this ACAP, including the issue of negligible discounting due to high oil prices, the 90 percent balancing account is fair and reasonable.

TURN points out that the 90 percent balancing account was a necessary element of the stipulation in order to gain PG&E's acceptance of other desirable features of the complete package. Further, TURN argues it will assure that other gas ratepayers will receive 90 percent of the benefit from the substantial increase in UEG load that can be expected as a result of the ongoing drought. Finally, TURN contends it protects other ratepayers in the event that oil prices remain high and PG&E experiences greater noncore throughput than is reflected in the stipulation. As TURN witness Florio testified in support of the stipulation:

"Well, PG&E is obviously concerned that the assumption of high oil prices may not be correct and, by the same token, I am concerned on behalf of customers that the throughput forecasts in this application may be too low; that I'm also particularly concerned that when

> the...if in fact the OIR takes effect on August 1st as scheduled that will have a variety of impacts that might otherwise lead PG&E to overcollect its noncore requirement.
>
> "So it was my feeling that there was a significant risk to customers that they would be paying too much that this balancing account would help to mitigate." (Tr. Vol. 6, p. 378.)

Thus, PG&E, TURN, and DRA all justify the adoption of a 90 percent balancing account for noncore transportation revenues as a key element of the stipulation and a reasonable outcome for this ACAP proceeding in the best interests of the utility and ratepayers alike.

c. CIG Et Al.'s Position

CIG et al. believes the Commission should not adopt the 90 percent balancing account for this ACAP period because of its conflict with the 75 percent balancing account protection adopted as a rule for the new gas industry structure due to be implemented August 1, 1991 pursuant to D.90-09-089. CIG et al. points out that PG&E was a signatory to the settlement proposal in the Procurement OIR, R.90-02-008, which advocated the 75 percent figure which was adopted in D.90-09-089. CIG et al. argues that the acceptance by the Commission of the 75 percent balancing account proposal was predicated on a belief that the lengthening of the period between cost allocation proceedings from one year to two years would increase utility revenue risk. CIG et al. alleges that the Commission favors less, not more, noncore revenue protection as a matter of policy. CIG et al. call the 90 percent balancing account proposed in the Stipulation a "transparent deal sweetener" (CIG et al. Opening Brief, p. 4).

Finally, CIG et al. alleges there is no basis in the record of this proceeding to justify an increase in balancing account protection. CIG et al. believe that if the record does not support a contested element of a stipulation the Commission is precluded from adopting it because the Commission's decision would then lack the support required to permit meaningful judicial review.

d. **Discussion**

The Stipulation's 90 percent balancing account treatment seemingly conflicts with our adoption of a 75 percent balancing account in D.90-09-089. However, if we took the view that parties could never propose alterations to our existing policies, we would be admitting an unwillingness to adapt to changing circumstances. Indeed, our "new" gas industry structure has been a changing one since its inception in May 1988. We must examine the 90 percent balancing account in the context of which it arose in this proceeding. The issue really is whether we are so troubled by the 90 percent balancing account that we want to change what the parties describe as one of the key elements of a stipulation supported by diverse interests.

CIG et al.'s arguments that there is no record to support the 90 percent balancing account are simply wrong. Testimony of the panel members for PG&E, DRA, and TURN in support of the entire stipulation given on the last day of hearings explained the parties' rationale for agreeing to a 90 percent balancing account. Prior to negotiating the stipulation, PG&E requested 100 percent balancing account treatment for noncore transportation revenues in its supplemental testimony. (Exhibit 2.) DRA and TURN opposed this in their testimony (Exhibits 9 and 14). The panel members testified that the 90 percent figure was a compromise and a critical element for reaching a stipulation that resolved so many issues. There is certainly as much support in this record, if not more, as there was in R.90-02-008 for the 75 percent balancing account figure adopted there. CIG et al.'s arguments that we cannot adopt a different figure for PG&E for this ACAP forecast figure because we have no record on the subject is without merit. Finally, we note that CIG et al. did not attend any hearings in this proceeding, choosing not to avail themselves of the opportunity to either offer testimony against the 90 percent figure or cross-examine the panel members as to their reasons for supporting a 90 percent balancing account treatment.

Turning again to the merits of whether we want to alter the stipulation in light of D.90-09-089, we do not believe it is necessary in this case to substitute our judgment for that of such a diverse group of stipulating parties. Obviously, the parties were aware of our selection of a 75 percent balancing account approach in D.90-09-089 during their settlement negotiations. Clearly, the 90 percent treatment was thought to be a better approach given the circumstances that arose during this proceeding, particularly the Gulf War. The fact that the war is now over does not automatically eliminate the justification put forth by the stipulating parties for a 90 percent balancing account. Since the stipulation implicitly assumes relatively high oil prices because of the minimal level of discounting forecasted, if oil prices drop substantially, the balancing account will protect both PG&E and its ratepayers.

The stipulation provides that this 90 percent balancing account remain in effect until implementation of rates resulting from PG&E's next cost allocation proceeding. This is scheduled to occur on April 1, 1992. However, that date may be subject to some slippage. Accordingly, we will make it explicit that the 90 percent balancing account approved today will convert automatically to a 75 percent balancing account on May 15, 1992, without further Commission action.

In conclusion, we are not persuaded to alter such a major component of the stipulation reached in this ACAP. Changing the 90 percent balancing account provision goes beyond mere "tinkering" with the stipulation, and would deprive the parties of a major benefit of their bargain.

C. Is the Stipulation, as a Whole, in the Public Interest?

Rule 51.7 of our Rules of Practice and Procedure allows us to reject a proposed stipulation whenever we determines that the stipulation is not in the public interest. We find no reason to do so with the stipulation before us in this proceeding. Rather, we believe an adequate record has been developed in this proceeding to allow us to make a finding that the stipulation is in the public interest and will be adopted in its entirety. The one caveat to that finding, pending review of the comments on the ALJ's proposed decision, relates to the take-or-pay costs forecast already discussed above.

We have acknowledged in prior decisions the strong public policy in California favoring settlements and the propriety of settlement in utility matters. (D.88-12-083, 30 CPUC 2d 189, 221-223.) If our goal truly is to encourage settlements or stipulations, then we must resist the temptation to alter the results of a good faith negotiation process unless the public will be harmed by the agreement. Otherwise, parties will legitimately grow wary of our settlement process if we alter settlements as a matter of course. Substituting our judgment for that of the parties is only appropriate if the public interest is in jeopardy. Despite the arguments of CIG et al. regarding the balancing account issue, we find the public interest is well served by the stipulation before us today.

IV. Contested Issues Not Addressed By The Stipulation

A. Allocation of Long-Term Contract Revenues

PG&E, DRA, and TURN all propose different methods for allocating revenues from long-term contracts. At hearing, three contracts were at issue: Mojave Cogeneration, C&H Sugar and Luz Solar Partners. The C&H Sugar and the Luz Solar Partners contracts were pending Commission approval. The stipulating parties agreed that only revenues from contracts approved by the Commission prior to preparation of the update exhibit should be included. Since the close of hearing, Commission Resolutions G-2930 and G-2932 rejected both of those contracts. Therefore, here we will only be addressing the appropriate allocation of the Mojave Cogeneration contract revenues.

1. <u>PG&E's Position</u>

PG&E proposes to treat revenues from Commission-approved long-term gas transportation contracts as a credit to base revenues and to allocate that credit to all remaining customers on the basis of average year throughput. PG&E points out there are two issues to be resolved with regard to long-term contract revenues. First, is the method for accounting for the revenues, either as revenue credits or as a revenue shortfall. Second, is how to allocate the revenue credit or shortfall, either on an equal cents per therm basis or based on an equal percent of base revenues plus pipeline demand charges.

PG&E acknowledges that the allocation results of its revenue credit approach and DRA's revenue shortfall are essentially the same. PG&E argues its approach is preferred because it is simpler to implement and is already familiar to the Commission, having been adopted for the treatment of EOR and interutility transportation revenues.

PG&E also maintains that its allocation on an equal cents per therm basis (which is the same as DRA's) is more appropriate than TURN's proposal that allocation be on the basis of base revenues plus pipeline demand charges (modelled on allocation for EOR contracts). PG&E contends that its approach uses the same method adopted by the Commission in D.87-05-046 for the allocation of GC-2 long-term contract revenues. PG&E states that decision also rejected the EOR model for allocation of revenues from long-term contracts for industrial customers with alternate fuel capabilities, e.g. GC-2 customers. (D.87-05-046, pp. 16-19.)

Since the Mojave Cogeneration contract is for an industrial customer with alternative fuel capabilities, PG&E believes its proposed equal cents per therm allocation is consistent revenue allocation treatment for long-term contract revenues whether or not technically GC-2 contracts. The important similarity is that the contracts are for industrial customers with fuel switching capabilities. PG&E urges the Commission to continue to track non-EOR long-term contract revenues on an equal cents per therm basis.

2. DRA's Position

DRA also acknowledges that the end result in terms of cost allocation between its method and that of PG&E is virtually the same. However, DRA contends that the philosophy of how you get to the end result is substantially different. DRA believes that the Mojave Cogeneration contract should not be treated as a base revenue credit because it is not an EOR contract. DRA argues that long-term, non-EOR contracts should be treated as revenue shortfalls, also citing D.87-05-046 (p. 7) in support of its position. However, both DRA and PG&E agree that whether its a credit or shortfall, it should be recovered from all other customers on an equal cents per therm basis.

3. TURN's Position

TURN disagrees with the equal cents per therm proposal of both PG&E and DRA, believing it to be the wrong allocation method for the Mojave Cogeneration contract. TURN argues that comparing the Mojave contract to the old GC-2 contracts is inappropriate. TURN contends that the GC-2 contracts were not designed to capture incremental sales or forestall bypass. TURN describes them as five-year transportation contracts based on the equivalent margin embedded in the utility's sales rates, which is retrospect, were very low at the time. According to TURN, customers who signed up for those GC-2 contracts were able to lock into very low rates compared to the tariff rates that went into effect shortly thereafter. TURN alleges that the Commission viewed the resulting revenue shortfall from these contracts as a "transition cost" for allocation purposes of the new gas industry structure.

TURN declares that the Mojave Cogeneration contract is nothing like the GC-2 contracts. TURN argues that the Mojave contract are more akin to the long-term EOR contracts approved by the Commission because it is an anti-bypass contract. TURN also cites D.87-05-046 for authority for its view that because of Mojave's similarity to EOR contracts, the appropriate allocation mechanism is that the revenues should be treated as incremental and credited back to other customers based on an equal percentage of base revenues plus pipeline demand charges.

TURN witness Florio testified that this method produces an allocation of about 77% core and 23% noncore. He goes on the state that "[s]ince core customers bear a much larger portion of the base revenue requirement, they should also receive a larger portion of incremental revenues such as these." (Ex. 14, p. 20.)

Finally, TURN argues that since, in its opinion, both the PG&E and DRA witnesses were poorly informed as to the details of the Mojave contract, the recommendation of its own witness should be adopted.

B. CIG et al.'s Position

CIG et al. submitted no testimony on this issue, but do attack TURN's proposal in its brief. CIG et al. dispute that long-term non-EOR contracts (like Mojave) can be likened to EOR contracts. CIG et al., like each other party, cites D.87-05-046 for support of its position. CIG et al. state that EOR customers are situated "quite differently" than industrial customers who may have the leverage to negotiate long-term contracts at rates below standard service levels. CIG et al. argue that industrial customers are not in a position to "bypass" California utilities in the traditional sense. However, according to CIG et al., the EOR customers, given their geographic concentration, strong demand for gas transportation and very real possibility of direct service from interstate pipelines, can indeed bypass the California gas distribution system in a manner beyond the reach of industrial customers.

CIG et al. further argues that D.87-05-046 did not explicitly treat the revenue shortfall resulting from the locking-in of equivalent margin rates under long-term contracts as a "transition cost." CIG et al. alleges that the utilities were ordered to directly assign the throughput volumes associated with these contracts, with costs matching the revenues flowing from them. According to CIG et al., any shortfall between the costs so assigned and embedded costs would be allocated to remaining customers on an equal cents per therm basis, thus essentially treating the shortfall as a transition cost. CIG et al. contend that the Commission's desire to obtain the fairest treatment of these costs rather than its opinion as to their nature as transition costs caused the allocation method adopted (D.87-05-046, mimeo. p. 16).

Finally, CIG et al. allege that as opportunities for the execution of long-term contracts increase with the implementation of capacity brokering programs, the future revenues associated with such contracts may be far greater than they are today. CIG et al. counsel against adopting a methodology in this case that departs from the allocation method deemed most fair in 1987. So long as the allocation is done on an equal cents per therm basis, CIG et al. are indifferent as to whether those revenues are treated as shortfalls or credits.

1. <u>Discussion</u>

With some trepidation we take note of the fact that all parties to this issue cite D.87-05-046 for support of their seemingly divergent positions. The disagreement among the parties boils down to which kind of contract discussed in that 1987 decision the Mojave contract is most like. Once each party answered that question, it found a passage in D.87-05-046 that supposedly supported its view.

We agree with DRA, PG&E, and CIG et al. that revenue allocation on an equal cents per therm basis for the Mojave Cogeneration contract is the most appropriate and consistent with D.87-05-046. We are unpersuaded by TURN's attempt to analogize this contract to EOR contracts for allocation purposes. The Mojave Contract is not an EOR contract.

As to the debate between PG&E and DRA over the revenue credit vs. shortfall issue, we find this argument to be "much ado about nothing" in that both parties agree there is no practical difference in result from their two theories. We agree with PG&E that its revenue credit approach is easier to implement. On that basis, all other things being virtually equal, we will adopt PG&E proposal to treat the Mojave Cogeneration revenues as revenue credits.

In conclusion, we adopt PG&E's position on the issue of allocation of the Mojave Cogeneration contract revenues in its entirety.

C. Cogeneration Rates

1. Overview

The controversy over whether or not the G-COG rate schedule should be changed so that rates are set on a forecast basis was addressed by three parties in the proceeding: PG&E, DRA, and California Cogeneration Council (CCC). PG&E is proposing a change from the current system of establishing rates on a monthly basis based on the actual average UEG rate (lagged by 60) days to a rate based on the adopted UEG/Cogeneration cost allocation and throughput forecast. CCC opposes PG&E's proposal in its entirety while DRA is opposed unless the problems created for Standard Offer 4 (SO4) Payment Option 3 cogenerators is resolved.

2. PG&E's Position

PG&E argues that problems with the current method for setting the G-COG rates prompted it to propose a change to a forecast basis which is consistent with the approach adopted for Southern California Gas Company (SoCalGas) in D.90-01-015. Fundamentally, PG&E alleges that the current method leads to an asymmetric risk which makes it more likely for PG&E to undercollect rather than overcollect revenues allocated to cogeneration customers.

Currently, when UEG throughput is higher than forecast, the average UEG rate is lower than forecast. This is because the UEG rate has both a demand and a volumetric component. Thus, when UEG throughput is higher than forecast, the demand component is spread over more volume than expected, which results in a lower average rate. Therefore, PG&E claims that the Schedule G-COG rates based on the actual UEG rates are lower than forecasted. As a result, PG&E undercollects. PG&E alleges this is exactly what the CSA was designed to address and evaluates the CSA during the first two years of industry restructuring to show actual UEG rates were substantially below forecast (Ex. 3, p. MCM-4).

PG&E states that in reverse circumstances it cannot overcollect from the G-COG customers because cogeneration rates do not increase as do UEG average rates when UEG throughput is lower than forecast.

PG&E points out that when the CSA was eliminated for SoCalGas, the underlying problem was removed by changing cogeneration rates to a forecast basis. (D.90-01-015, p. 101.)

Moreover, PG&E contends that the current approach disadvantages PG&E due to forces largely beyond its control, i.e. the fluctuations of UEG throughput are driven largely by the amount of hydro generation.

PG&E points out that for two-thirds of the power it purchases under this rate schedule, the change to a forecast basis will result in a consistent treatment for cogenerators' costs (gas) and revenues (electricity). As PG&E witness Schneider testified:

> "Second, most cogeneration power-purchase prices (i.e., the prices utilities pay to cogenerators for their electricity) are set on a forecast basis. Some cogenerators themselves have expressed a preference for consistent treatment of their costs (gas) and revenues (electricity). PG&E agrees that having a fixed-in-advance power-purchase price and an after-the-fact gas price is confusing and sends cogenerators convoluted price signals.
>
> "PG&E believes that the proposal to fix the cogeneration transportation rates at the forecasted UEG/cogeneration rate would allow the company a fair chance to recover its authorized revenue requirement. Adoption of PG&E's proposal would also make the rate treatments for SoCalGas and PG&E the same." (Exhibit 1, p. 8-11.)

PG&E acknowledges that for one-third of the power it purchases, cogenerators on the S04 Payment Option 3, its proposal to move to a forecast basis would make things inconsistent. PG&E denies that there is a contradiction inherent in its position:

> "Q But isn't there some contradiction in solving the problem for some customers, whatever percentage that may be, and at the same time imposing that on another group?
>
> "A Absolutely not. I think that to the extent that we are solving the problem for most of the power that we buy, and perhaps causing some difficulty for the other part of that, that could be what the Commission could address in an electricity case.
>
> I believe that our proposal would make things better, and to that extent I do not think it is inconsistent." (Schneider, Tr. Vol. 2, p. 88.)

Finally, PG&E points out that while CCC, representing one group of cogenerators, opposes its proposal, other cogenerator groups who are parties to the case took no position whatsoever on the issue.

3. CCC's Position

CCC opposes PG&E's proposal as inappropriate to consider in an ACAP proceeding while acknowledging that linkage between cogenerators costs and revenues has conceptual merit. However, CCC disagrees with PG&E that it is appropriate to "solve a problem" for two-thirds of power purchased while creating a problem for the remaining one-third.

CCC believes it is inappropriate for PG&E to refer to the elimination of the CSA and undercollection of revenues in support of its proposal, arguing that PG&E did not explicitly state such arguments in its testimony.

CCC believes the change to a forecast approach in the SoCalGas ACAP (D.90-01-015) arose out of very different circumstances and should not be used to justify a change for PG&E. CCC argues that the cogeneration customer base of the two utilities are significantly different. CCC alleges that in the SoCalGas' territory, only one cogeneration customer purchases power under a S04 Payment Option 3 contract, while in PG&E's territory these cogenerators provide one-third of all power purchased.

CCC also urges rejection of PG&E's proposal because cogenerators selected the Payment Option 3 contract option based on an understanding that both their energy payments and gas costs would be based on recorded UEG gas costs. CCC contends that PG&E is effectively changing the nature of the original agreements by advocating a rate design change for the S04 Payment Option 3 cogenerators. CCC dismisses PG&E's argument that the methods to calculate the gas rate to cogenerators have varied since 1984. CCC argues that PG&E's cogeneration gas rate methodology has never varied from actual rates. CCC believes that the impact, in terms of risk, of changing from an actual to forecasted rate cannot be compared to routine changes in methods of calculation.

Finally, CCC concludes that it is bad precedent to fix one problem by creating another in altering rate design methodology.

4. DRA's Position

DRA believes that no change should be made to the cogeneration rates without solving the potential problems of the SO4 Payment Option 3 cogenerators. DRA goes on to state that the ACAP proceeding is an improper proceeding to alter contract terms for cogenerators. Finally, DRA stresses that the Commission should listen to the concerns raised by those persons (apparently represented by CCC) who will be affected by the proposal and reject PG&E proposed change.

5. Discussion

This issue was addressed in last year's ACAP decision, although the original proponent of the change had been TURN in that proceeding. PG&E has more fully developed the record in support of its proposal in this year's ACAP and all parties had an adequate opportunity to examine, attack, or propose alternatives.

We believe that PG&E's proposal will have benefits for a significant number of cogenerators as well as for PG&E itself. However, to the extent that SO4 Payment Option 3 cogenerators are adversely affected, which the CCC seems to argue in its briefs, we have the concern that we are changing rules in the middle of the game.

There appear to be a variety of methods to remedy the concerns of the SO4 Payment Option 3 cogenerators. Taking steps at this time, and in this proceeding to effect long term fixes in order to fully implement PG&E's proposal would be beyond the scope of this proceeding. The necessary modifications would involve a review of energy payments made by the utilities to cogenerators which is inappropriate at this time.

We will, therefore, implement PG&E's proposal with the exception that SO4 Payment Option 3 cogenerators will not be held, at this time, to moving to a PG&E G-COG rate which is based on a forecast. This is a temporary measure which will be in effect only until the appropriate modifications are made to the SO4 Payment Option 3 cogeneration contracts in the subsequent phase of the Biennial Resource Plan Updating Proceeding (BRPU) in I.89-07-004. At that time, this issue will be reviewed and the temporary exemption from the forecast gas rates under PG&E's G-COG tariff will be lifted for SO4 Payment Option 3 cogenerators. We expect the Payment Option 3 cogenerators to pursue modifications of their avoided cost contracts in good faith in the BRPU based on their methodological support of PG&E's proposal in this proceeding.

Partially implementing PG&E's proposal will require PG&E to establish tariffs which provide for both a G-COG rate based on a forecast of UEG rates and a G-COG tariff based on actual UEG rates. The G-COG tariff based on actual UEG rates will be eliminated once the issue is addressed in the BRPU.

Finally, we reject CCC's argument that PG&E improperly argued protection of its revenue requirement in support of the switch to forecasted rates because it had not been developed in testimony. Already quoted above is PG&E's witness Schneider's testimony where she states that her proposal "would allow the company a fair chance to recover its authorized revenue requirement." (Ex. 1, p. 8-11.) If CCC failed to pursue what she meant by that statement during its cross-examination, it cannot now argue a new theory being raised in briefs. All parties are entitled to formulate arguments in briefs that rely on testimony. In fact, argument properly belongs there rather than in testimony.

D. Cogeneration Shortfall Account

1. Overview

In last year's ACAP decision, D.90-04-021, we ordered PG&E to discontinue entries to the CSA account. We also deferred recovery of the existing balance until this proceeding in order to allow for a detailed audit of the transactions in the account. The issue for this case is what is the appropriate amount for recovery. The original testimony of PG&E, DRA, and CCC indicated more disagreement than exists in their respective briefs on this subject.

2. PG&E's Position

PG&E believes that the entire balance of the CSA should be authorized to be recovered in rates. PG&E points out that the DRA audit of the account has occurred with no irregularities found (Tr. Vol. 3, p. 157).

During hearings, PG&E believed that due to a Commission error in last year's decision, the CSA balance had inadvertently been included in rates for last year's ACAP. Further analysis by PG&E after the close of hearings resulted in the affidavit of Susan R. Schneider being attached to PG&E's Opening Brief. In her affidavit, Ms. Schneider declares that although the CSA balance was included in cost allocation tables, it was not included in those costs actually allocated to the various customer classes in the cost allocation/rate design process and therefore <u>is not</u> included in current rates.

PG&E requests that its $1.1 million figure be authorized for recovery in rates and that the conditions recommended by DRA and CCC need not be imposed.

3. <u>DRA's Position</u>

In its opening brief, DRA recommended recovery of the amount in the CSA subject to four conditions. These conditions are: 1) there be a rate limiter which restricts the amount booked to the CSA as the difference between the otherwise applicable rate and forecast UEG rate; 2) corrections of entries in the CSA where the cogeneration shortfall difference was calculated on the basis of actual UEG rates instead of the forecasted UEG rate; 3) no interest recovery; 4) if any money in the CSA was collected pursuant to D.90-04-021 (last year's ACAP decision), it should be offset.

DRA acknowledges the accuracy of Ms. Schneider's affidavit, concluding that $1,078,905 should be authorized for recovery in rates.

E. <u>CCC's Position</u>

Originally CCC opposed any recovery by PG&E of the CSA. During hearings, CCC determined it would support PG&E proposal to collect the CSA also conditioned on four factors: 1) there must be a revenue shortfall from the cogeneration class; 2) collection should be conditioned on the existence of a rate limiter at the forecasted UEG rate; 3) the Commission should determine whether DRA had adequately audited the account; and 4) any monies collected since last year in rates should be credited toward the total.

1. Discussion

There is now general agreement that PG&E is entitled to recover some amount from the now defunct CSA. The update exhibit lists the amount of $1,106,000 (Ex. 28) while DRA's reply brief uses a figure of $1,078,905. DRA explains its figure by inserting a zero entry in the ten instances shown in PG&E's Exhibit 3 Table 1 where "actual rate paid" exceeded the "average adopted UEG rate." Obviously the difference in dispute has little impact. In light of the fact that DRA's witness did not testify to any irregularities in her audit report, we are inclined to adopt PG&E's figure. We are relieved that the balance was not inadvertently recovered in last year's ACAP rates. Given the dollars involved, we find the conditions recommended by DRA and CCC to be unnecessary and burdensome. We shall authorize recovery of the $1,106,000 listed in Exhibit 28 for the CSA.

V. Refund of Core-Elect Purchased Gas Account

A. Background

An unexpected issue arose in the comments on the proposed decision due to the size of the overcollection in the core-elect Purchased Gas Account (PGA), shown to be $46,694,000 in Tables 4 and 6 of the proposed decision. In its original testimony, PG&E had estimated this number to be approximately $10 million. The update exhibit of February 1991 likewise did not indicate the size of the core-elect overcollection because the Revenue Requirement Summary Table indicated a Core PGA Balance of $24,532,000 (a net figure of the core-elect PGA and the core PGA revenue. Thus, several parties were shocked at the size of the account in the tables of the proposed decision.

More importantly, several parties pointed out the negative consequences of allowing this overcollection to be offset against the core-subscription procurement rate PG&E can offer. Gasmark et al., CIG et al., TURN, and DRA all believe that offsetting this overcollection against PG&E's core-subscription procurement rate would lower the rates PG&E could offer core subscription customers. The rate decrease based on the $46.7 million overcollection would be approximately 15 cents per decatherm, which amounts to about seven percent. This would impact the competitiveness of the rate that gas marketers charge to noncore customers under the new procurement rules.

The parties point out that if PG&E and the rest of the California gas industry were not on the verge of a major structural change, the implementation of the procurement OIR rules, (R.90-02-008) the amortization of this core-elect overcollection would not be a major cause for concern. Unfortunately, however, the existence of a seven percent "credit" in core subscription rates will create serious equitable and competitive problems when the OIR is implemented on August 1, 1991.

As TURN succinctly states, part of the Commission's rationale in launching the procurement OIR in the first place was the concern that the large volume of core election in PG&E's service territory was thwarting the development of a truly competitive noncore procurement market. Indeed, certain aspects of the OIR were specifically designed to make core election (subscription) less attractive. These efforts would be severely undermined if the new core subscription service were to start out with a seven percent rate credit advantage, due solely to the after-effects of the previous industry structure and rules. Potentially, the seven percent credit may be too large a competitive advantage for competing gas suppliers to overcome, resulting in the virtually unanimous core subscription that this Commission tried so hard to undo.

All of the parties concerned about the potential consequences of amortizing the $46.7 million overcollection as a credit to future rates argue instead for a direct refund of the overcollection on an equal cents per therm basis to all customers who used core-elect service during the period between the issuance of last year's ACAP decision (D.90-04-021) and today's decision.

In its reply comments, PG&E does not endorse a refund scheme, but neither does it demand that we hold hearings on this issue. PG&E mainly seems concerned that a refund program not set a precedent in other cases, but be based rather on the unique circumstances of the gas industry restructuring at the present time. Further, PG&E requests that if the Commission opts for a refund, it be allowed to credit customer accounts rather than issue refund checks and be given adequate time for data collection and administration.

B. Discussion

It is unusual for an issue such as this to catch all parties to the proceeding by surprise. We agree with TURN, DRA, Gasmark et al., and CIG et al. that amortizing these overcollected dollars to reduce core-elect and core-subscription rates in the ACAP test period would negatively impact the structural changes we hope to achieve through our new procurement rules effective August 1, 1991. If this problem had been brought to our attention during hearings, we would have solicited testimony from the parties on the appropriate mechanism for correcting this problem. However, given the unanimity among the parties (except PG&E) as to the appropriateness of a refund under these circumstances and our desire to place PG&E's new rates into effect as soon as possible, we will decide the issue here without hearings. We note that PG&E did not demand hearings in its comments on the proposed decision and we commend PG&E in advance for its acquiescence to our solution to this dilemma.

We agree with PG&E that we are instituting a refund only because of the special circumstances discussed above related to the gas industry restructuring this summer. We are not establishing a precedent that under- and overcollections are to be eliminated in the future by refunding or back-billing customers, as necessary, based on prior usage. Here, we are only concerned with eliminating the competitive advantage that amortization of the overcollection would give PG&E.

Therefore the core-elect PGA balance will be zeroed out as of today's date. That balance as of May 8, 1991, will be refunded to the core-elect customers who caused its accrual. The total balance will be different from the $46.7 million figure because of the passage of time since the update exhibit was prepared. Also, we note we are only refunding the core-elect PGA not the core PGA. We direct PG&E to refund the balance to the core-elect customers of the 1990-91 ACAP period on an equal cents per therm basis. PG&E shall credit these customers' accounts rather than issuing refund checks in order to limit administrative costs. PG&E shall have 120 days from the effective date of its tariff schedules filed in compliance with this decision to administer the refund.

VI. TURN's Request for Finding of Eligibility for Compensation

On January 8, 1991, TURN filed in this proceeding a Request for Finding of Eligibility for Compensation, under Article 18.7 of the Commission's Rules of Practice and Procedure. No response to TURN's request has been filed by any other party. Article 18.7 contains the requirements to be met by intervenors seeking compensation "for reasonable advocate's fees, reasonable expert witness fees, and other reasonable costs...of participation or intervention in any proceeding of the Commission initiated on or after January 1, 1985, to modify a rate or establish a fact or rule that may influence a rate." This decision orders PG&E to decrease its rates by approximately $47 million and therefore clearly falls within the definition of applicable proceedings.

Rule 76.54 requires filing of a request for eligibility within 30 days of the first prehearing conference or within 45 days of the close of the evidentiary record. TURN's request was filed on January 8, 1991, within 45 days after the close of hearings in this proceeding.

Rule 76.54(a) requires that a request for eligibility include four items:

> (1) A showing by the customer that participation in the hearing or proceeding would pose a significant financial hardship. A summary of the finances of the customer shall distinguish between grant funds committed to specific projects and discretionary funds;
>
> (2) A statement of issues that the customer intends to raise in the hearing or proceeding;
>
> (3) An estimate of the compensation that will be sought; and
>
> (4) A budget for the customer's presentation.

The adequacy of TURN's filing on each of these items is addressed below.

A. Significant Financial Hardship

Rule 76.52(f) defines "significant financial hardship" to mean both of the following:

> "(1) That, in the judgment of the Commission, the customer has or represents an interest not otherwise adequately represented, representation of which is necessary for a fair determination of the proceeding; and,
>
> "(2) Either that the customer cannot afford to pay the costs of effective participation, including advocate's fees, expert witness fees, and other reasonable costs of participation and the cost of obtaining judicial review, or that, in the case of

> a group or organization, the economic interest of the individual members of the group or organization is small in comparison to the costs of effective participation in the proceeding."

TURN contends that it represents an interest - the residential customer class - that would not otherwise be adequately represented in this proceeding. TURN points out that the Commission has specifically found that participation of the Division of Ratepayer Advocates does not obviate the need for residential class representation. (D.85-06-028, mimeo. at 2-3.) Circumstances have not changed in this regard since that time. Thus for 1991, TURN meets the requirement of Rule 76.52 (f)(1).

For an organization like TURN, Rule 76.52(f)(2) weighs the economic interests of the organization's individual members against the cost of effective participation. TURN states it represents the interests of several constituent groups such as the Golden State Mobilehome Owners League, the International Association of Machinists and Consumer Action, whose members include individual residential customers of PG&E, as well as approximately 30,000 individual members, many of whom receive utility service from PG&E. TURN submits that the Commission has consistently found that the economic interests of these individual members are tiny in comparison to the costs of effective participation in Commission proceedings. TURN points out that in every year since the current compensation rules were adopted, this Commission has found that TURN qualifies as a "customer" suffering significant financial hardship.

As discussed below, TURN's estimated cost of participation in this proceeding is $40,000. While not addressing the reasonableness of TURN's estimated budget, we do agree with TURN that the economic interests of its members are individually much smaller than the amounts TURN has estimated to have spent in this proceeding. We conclude that TURN, as an experienced organization representing residential customers, meets the requirements of Rule 76.52(f)(2) for 1991.

In addressing the significant financial hardship issue under Rule 76.54(a)(1), TURN is also required to provide a summary of finances distinguishing between grant funds committed to specific projects and discretionary funds. TURN provided such information for the fiscal year ending June 30, 1990 and July 1 through November 30, 1990. During the 17-month period, TURN's total income was approximately $1.15 million. Included in the figure are direct mail expenses of nearly $400,000 and $230,000 restricted to the Telecommunications Education Trust (TET) grant program which cannot be used to support TURN's ongoing advocacy activities. TURN's end-of-November fund balance was approximately $310,000, a portion of which is restricted TET money. Intervenor funding contributed $270,000 during that 17-month period, representing a significant percentage of discretionary income.

TURN argues that intervenor compensation is critical in maintaining TURN's financial health and an important part of its total budget. TURN points out that its operating expenses have increased substantially, as the full effects of the organization's move to new office space and addition of new staff have been felt. TURN contends that without intervenor funding, it will not be able to effectively participate in Commission proceedings and will suffer significant financial hardship.

We agree that intervenor funding is a significant portion of TURN's budget that cannot be met from other sources. We conclude that TURN has met the requirements of Rule 76.54(a)(1) and has shown that its participation in this proceeding would pose a significant financial hardship.

B. <u>Statement of Issues</u>

Rule 76.54(a)(2) requires a statement of issues that the party intends to raise. TURN states that the issues raised by it in this proceeding are already matters of record, particularly as set forth in its prepared testimony participation in the stipulation. TURN addressed a wide variety of issues, including the industrial demand forecast and discount adjustment issue, oil, and gas pricing forecast, interutility throughput and aspects of cost allocation and rate design.

A review of the record and this decision provide clear evidence that TURN has complied with Rule 76.54(a)(2).

C. Estimate of the Compensation to be Sought

Rule 76.54(a)(3) requires an estimate of the compensation to be sought. Before the decision was issued, TURN estimated it may request $40,000 for its work in this case, based on an assumed 150 hours of attorney/witness time at a proposed hourly rate of $215, plus $6,500 in consulting fees for its second witness, plus $1,250 for "other reasonable costs", primarily postage and copying expenses.

In light of TURN's participation in this proceeding, TURN has complied with Rule 76.54(a)(3).

D. Budget

Rule 76.54(a)(4) requires a budget for the party's presentation. As discussed above, TURN's estimated budget for this proceeding is $40,000.

TURN has complied with Rule 76.54(a)(4). The reasonableness of this estimate will be considered if and when TURN requests compensation in this proceeding.

E. Conclusion

We have determined that TURN has shown that its participation in this proceeding would pose a significant financial hardship, as defined in Rule 76.52(f), and has submitted the summary of finances required by Rule 76.54(a)(1). This "significant financial hardship" determination will carry over to TURN's participation in other proceedings in 1991.

For purposes of this proceeding only, TURN has met the full requirements of Rule 76.54(a). In addition, no party has responded to TURN's request. We find TURN to be eligible for an award of compensation for its participation in this proceeding.

TURN is placed on notice that it may be subject to audit or review by the Commission Advisory and Compliance Division, therefore adequate accounting records or other necessary documentation must be maintained by the organization in support of all claims for intervenor compensation. Such record keeping systems should identify specific issues for which compensation is being requested, the actual time spent by each employee, the hourly rate paid, fees paid to consultants and any other costs incurred for which compensation may be claimed.

VII. Transcript Corrections

By letter dated December 7, 1990, PG&E requested certain corrections to the transcript. We accept these corrected changes. They will be made in the Commission's official transcript.

Findings of Fact

1. In light of the uncertainties caused by the Gulf war and the upcoming changes in the gas industry, PG&E, DRA, and TURN met in an attempt to reach agreement on various issues in this proceeding before the hearings were scheduled to begin in November.

2. The resulting stipulation was signed by PG&E, DRA, CPG, the City of Palo Alto, SCE, and TURN and received in evidence as Exhibit 27.

3. The motion filed by PG&E for a waiver of Rule of 51.6(c) was granted because even though the timing was handled differently, the goals of the settlement rules had been reached in this proceeding.

4. The stipulating parties stress that given the uncertainty of the war in the Middle East and its impact on future oil prices as well as the upcoming implementation of D.90-09-089, the stipulation is a reasonable compromise of the various positions of the parties as set forth in their prepared testimony.

5. The stipulating parties agreed that it would be improper to give their stipulation any precedential weight in any future PUC proceeding.

6. The stipulating parties stressed that the numbers agreed upon for various elements were not intended to have a relationship to each other but were simply an effort to reach compromises that were reasonable.

7. Only one party, Salmon Resources Ltd., chose to cross-examine the stipulating parties on any of the underlying issues.

8. The forecast of alternate fuel prices is a critical element in the ACAP.

9. Due largely to the invasion of Kuwait by Iraq, PG&E was ordered to file supplemental testimony. PG&E claims it took this into account in forecasting the refiners average acquisition cost of imported crude oil (RAAC) as $20 per barrel during the ACAP period.

10. DRA recommended adoption of a RAAC of $29.15 for the ACAP period.

11. The stipulating parties expressly recognized the extreme uncertainty surrounding world oil markets and any forecast of a crude oil price caused by the war in the Middle East.

12. The disparity between PG&E's and DRA's oil price forecast in their original testimony is quite dramatic.

13. We concur with the stipulating parties that the approach reached in their stipulation regarding oil prices (Appendix D) is a reasonable outcome given the circumstances that surround this ACAP period.

14. The stipulation correctly incorporates an implicit assumption that oil prices will be high enough so that only minimal discounting will occur, yet recognizing the uncertainty by incorporating a 90% balancing account for non-core transportation revenues.

15. In a typical ACAP proceeding, the appropriate forecast of the cost of gas for the utility is an important piece of the current gas industry structure.

16. In an ACAP, estimates of the weighted average cost of gas (WACOG) for both the core portfolio and the non-core portfolio are developed.

17. In their original testimony, PG&E estimated a core WACOG of $2.31 per decatherm (Dth), while TURN forecasts a core WACOG of $2.18 per Dth. DRA predicted a core WACOG of $2.16 per Dth, and finally CPG forecasts a core WACOG of $2.17 per Dth.

18. The stipulation selects a core WACOG of $2.23 per Dth.

19. While the stipulating parties are able to agree that $2.23 per Dth is a reasonable forecast of the core WACOG, the parties do not agree on the underlying components of the forecast.

20. While the forecast of TURN, CPG, and DRA were all lower than PG&E's forecast, the percentage difference is fairly small.

The percentage difference between the highest forecast (PG&E) and the lowest (DRA) is less than 7%.

21. Thus the stipulating parties urge that adoption of $2.23 per Dth for the core WACOG, which is within 4% of each of their original forecasts, is a reasonable approach for the Commission to take.

22. We agree with the stipulating parties that their core WACOG of $2.23 per Dth is a reasonable compromise of their original positions.

23. With only a penny per Decatherm in dispute between DRA and PG&E we see no reason to do anything other than adopt the stipulation figure of $2.52 per Dth for the noncore WACOG.

24. PG&E originally forecasted 16.8 MMDth of G-P2B throughput, 129.1 MMDth of G-IND throughput and 9.1 MMDth of industrial GC-2 throughput.

25. DRA's original forecast is: 21.3 MMDth for G-P2B throughput, 169.4 MMDth for G-IND throughput and 9.1 MMDth for GC-2 throughput.

26. The stipulating parties compromised on their original position and agreed on the following forecast: 17.5 MMDth of G-P2B throughput, 138.3 MMDth of G-IND throughput, and 9.1 MMDth of Industrial GC-2 throughput. We agree that this is reasonable.

27. PG&E and DRA both originally forecast SCE Cool Water demand at 17.8 MMDth.

28. TURN's original forecast for Cool Water throughput was 24.9 MMDth.

29. SCE urged that whatever throughput forecast was adopted in the SoCal Gas ACAP should also be adopted in this proceeding.

30. The parties reasonably agreed in the stipulation to 24.9 MMDth for Cool Water demand. This stipulation forecast is derived from the 1990 California Gas Report in conjunction with the Cool Water forecast incorporated into SCE's September 1990 ECAC settlement agreement.

31. PG&E and DRA fundamentally agreed on the cogeneration throughput forecast, despite the fact that PG&E had forecast a slight amount of curtailment to these customers in its original filing.

32. The stipulation's cogeneration forecast, which incorporated PG&E's forecast of demand on rate schedule G-COG at 63 MMDth and the cogeneration throughput forecast of 6.6 MMDth for cogeneration customers served under GC-2 contracts is reasonable.

33. The stipulation forecast for the following throughput categories are: .1 MMDth for Industrial Interdepartmental, 1.1 MMDth for Steam Heat throughput, and 50.6 MMDth for EOR throughput. No other party forecast throughput for any of these categories.

34. PG&E and DRA were the only two parties to forecast UEG throughput, both agreeing on a 164.4 MMDth forecast of UEG demand.

35. PG&E and DRA disagreed slightly regarding UEG curtailments. PG&E originally forecast UEG curtailments of 21.4 MMDth while DRA originally forecast UEG curtailment of 13.9 MMDth.

36. The stipulating parties adopted a UEG throughput forecast of 146.3 MMDth. This throughput forecast assumes a level of curtailment of 18.2 MMDth, a compromise between the positions of DRA and PG&E in their original testimony.

37. PG&E forecasts 29.7 MMDth of curtailment occurring in several non-core classes. DRA forecasts 13.9 MMDth of curtailments all in Priority P5, which consists of UEG and EOR customers. TURN suggests that curtailments should be approximately 10MMDth less than what was forecasted by PG&E.

38. The stipulating parties adopted a level of curtailment of 20 MMDth, all occurring in Priority P-5.

39. The stipulation number is reasonable because it assumes that all curtailment is limited to customers in the lowest priority class, P-5. No other party disputed this figure in the stipulation.

40. There was no dispute among any parties in their original testimony as to PG&E's original forecast of 13.7 MMDth for wholesale throughput.

41. By adopting the above noncore throughput numbers as set forth in the stipulation, we give them no precedential significance for future proceedings before the Commission.

42. PG&E's and DRA's forecast of throughput for residential and commercial customers was practically identical in their original filings. For residential throughput PG&E originally forecasted 217.2 MMDth while DRA forecasted 210.7 MMDth. As to commercial throughput, PG&E forecasted 90.6 MMDth while DRA forecasted 91.1 MMDth.

43. The stipulation residential throughput forecast is 217.2 MMDth and its commercial throughput forecast is 90.6 MMDth.

44. Both PG&E and DRA agreed on the following numbers for these relatively small throughput items in their original testimony. Therefore the stipulation adopted these numbers as follows: .2 MMDth for core interdepartmental and 1.4 MMDth for PG&E UEG startup fuel.

45. The stipulation assumes a forecast of 8.2 MMDth for gas department use and 17.5 MMDth for LAUF. Given that there is no dispute over these numbers we find them to be reasonable.

46. DRA and PG&E originally forecasted cold year wholesale throughput the same as their average year forecast. TURN, on the other hand, forecasted an increase of 12 percent over average year conditions.

47. In the stipulation the parties compromise on their positions and predicted an increase of six percent over average year forecast, resulting in a cold year throughput forecast for wholesale customers of 14.6 MMDth.

48. As to the cold year throughput numbers to which there was no disagreement, we find they are reasonable.

49. We agree with the stipulation's acceptance of TURN's argument that because a significant component of wholesale customers' demand is residential and commercial an adjustment needs to be made in a cold year. Therefore, the 6 percent increase in the cold year wholesale throughput forecast is reasonable.

50. The forecast cold year curtailment of 37 MMDth incorporated in the stipulation is a reasonable number representing, once again, a compromise between the positions of PG&E, TURN, and DRA in their original testimony.

51. PG&E originally forecast 27.5 MMDth of interutility throughput, DRA, on the other hand, forecasted 53 MMDth, while TURN came in with the highest number, forecasting 70 MMDth.

52. The stipulating parties reached a compromise on their original positions agreeing to an interutility throughput forecast of 50 MMDth, 3.9 MMDth originating from California sources and 46.1 MMDth occurring from Topock to Kern River.

53. The stipulating parties agreed to an additional 2.1 cents per Dth to be incorporated into the forecast interutility rate to reflect an increase in interutility transport rates to collect gas gathering costs.

54. Selecting an interutility throughput number which is a compromise of all the parties' original testimony is a reasonable approach and will be adopted.

55. For the most part the stipulating parties relied on the determination of the revenue requirement as set forth in PG&E's prepared testimony.

56. Therefore there is no need in the text of this decision to describe the various credits and balancing accounts that are uncontroversial in this proceeding.

57. The update exhibit, submitted on February 19, 1991, which includes January 31, 1991, balancing account amounts, has been prepared in compliance with the terms of the stipulation, according to PG&E. This update indicates a net rate decrease (as compared to

present January 1, 1991 rates) of approximately $47,811,000 to PG&E. Overall this is a 2.1 percent decrease in revenue requirement.

58. The stipulating parties agreed that the EOR, NRSA and CFA Balancing Account balances should be adjusted to reflect the recommendations of the DRA audit of these accounts as described in DRA's prepared testimony.

59. With regard to the CFA account, the stipulation recommends that the balance in the allowance for doubtful accounts within the CFA debt service account be lowered to 5.4 percent of the outstanding loan portfolio balance as of the effective date of this decision.

60. As to the NSRA, the stipulation recommends that this balance be decreased by $4.535 million.

61. For the EOR balancing account, the stipulation recommends that the amount in the EOR balancing account be decreased by $319,222.

62. The stipulation recommends that the estimate of the PGT refund be updated to $6.8 million to reflect the amount actually received by PG&E. In the update exhibit these adjustments have been made to the core fixed costs account and to the pipeline demand charge true up amount as directed by the stipulation. No other party has presented testimony opposing this proposal.

63. The stipulation suggests that the balance in the natural gas vehicle (NGV) memorandum account should not be included in the revenue requirement for this year's ACAP. The stipulation proposes that the amount remain in the memorandum account to be allocated in PG&E's next cost allocation proceeding.

64. TURN in its prepared testimony proposed a different allocation of the RD&D adjustment between core and non-core than that proposed by PG&E. Specifically, TURN proposed to allocate $668,000 of the RD&D adjustment to the core and $412,000 to the non-core.

65. DRA proposed that the RD&D adjustment should be allocated based on cold year peak season throughput. DRA then proposed in its rebuttal testimony the position ultimately adopted by the stipulating parties.

66. The stipulation recommends that the total RD&D adjustment of $1.008 million be allocated as follows: $728,000 to the core and $352,000 to the non-core.

67. The stipulation further recommends that the Core Gas Fixed Account balance and the NRSA balance, respectively, be changed to reflect the RD&D amounts.

68. The stipulation adopts PG&E's proposal set forth its original prepared testimony to consolidate several balancing accounts. Specifically the proposal would:

1. Eliminate the Core/Core-Elect Surcharge Subaccount of the Core Purchased Gas Account by allocating the remaining balance between the Core Subaccount and the Core-Elect Subaccount,

2. Eliminate the Core Implementation Balancing Account by transferring the remaining balance to the Core Gas Fixed Cost Account,

3. Eliminate the Noncore Implementation Account and the Negotiated Revenue Stability Account by transferring the remaining balances to the Noncore Transition Cost Account.

No party disagreed with any of these recommendations.

69. The stipulating parties have agreed to two possible amounts for the brokerage fee to be included in the procurement revenue requirement (and credited against the transportation revenue requirement).

70. The Price Waterhouse Study recommends a gas brokerage fee of $6,637,163.

71. The parties had mutually agreed if the Price Waterhouse study figure was questioned, then the update exhibit would use the

$11.124 million figure escalated by appropriate factors set forth in the January 1, 1991, attrition decision. Therefore the update exhibit (Exhibit 28) shows the brokerage fee credit at $11,810,000.

72. The stipulating parties recognized an implicit assumption that oil prices will be high enough so that only minimum discounting would be required during the test period.

73. The stipulation puts forward the following discount factors: Rate schedule G-IND excluding Cool Water 98 percent; rate schedule G-P2B, 97 percent; and rate schedule G-COG, 99 percent.

74. PG&E and the other stipulating parties urged that these conservative numbers be adopted in light of circumstances surrounding this ACAP. We find this to be a reasonable approach in light of the continuing uncertainties regarding oil prices as result of the Gulf war.

75. The projected revenues from SCE Cool Water are based on the total forecast of 23.9 MMDth of throughput. The parties originally disagreed how this throughput should be priced.

76. The pricing finally agreed upon in the stipulation, consistent with that SCE's proposal, recognizes that some volumes at Cool Water will be served at the higher rate, i.e., the G-IND standard service rate, while the bulk of the throughput will occur at a price which is competitive with the alternative fuel price at SCE Cool Water, or SoCalGas' Tier 2 UEG rate.

77. Out of the 23.9 MMDth of Cool Water throughput, only 6 MMDth will be assumed to be priced at PG&E's G-IND standard service rate with the remaining 17.9 MMDth priced at 29.15 cents per Dth (which is the SoCalGas Tier 2 UEG rate adopted in D.90-11-023, SoCalGas' most recent ACAP decision).

78. We concur with the stipulation pricing for the Cool Water facility since it reflects the market reality associated with this plant.

79. The stipulation recommends that the Commission adopt the cost allocation methods set forth in PG&E's prepared testimony except as expressly noted in the stipulation. (Exhibit 7.)

80. Since no party has objected we find the stipulated cost allocation as set forth in Exhibit 27 is reasonable.

81. In the original testimony of the parties, only two issues arose with regard to core rate design: the level of residential Tier differential reduction and the calculation of the LIRA (Low-Income Ratepayer Assistance) credit.

82. The stipulation provides that the tier differential, measured by the ratio of Tier II rates to Tier I rates, should be reduced by maintaining the difference between the tiers and absolute terms.

83. We concur that stipulation proposal is a reasonable one to reduce the residential tier differential because it reflects the consensus of the parties.

84. PG&E recommended a change in the calculation of the LIRA credit from what was used last year. No party challenged PG&E's new approach. PG&E's proposal has been incorporated into the stipulation.

85. The stipulating parties recommend that LIRA volumes and revenues be fully credited to the core revenue requirement before allocating costs among non-LIRA residential and commercial classes.

86. We agree with the stipulating parties that this LIRA proposal is a reasonable one.

87. Except for a cogeneration issue, PG&E's rate design methodology for non-core rates was not challenged by any other party. We see no reason to do anything different than what has been done by PG&E as to these uncontroversial and uncontested rate design issues.

88. We must determine what is the appropriate amount to assume in the revenue requirement as take-or-pay costs that PG&E will have to pay during this test ACAP test period.

89. In their original testimony, both PG&E and DRA has estimated TOP costs of around $50 million.

90. The Stipulating parties propose a $27.5 million forecast of TOP costs to be incurred by PG&E during the test period.

91. While not signing the stipulation, California Industrial Group, California Manufacturers Association and California League of Food Processors (CIG, et. al.) join in support of the $27.5 million forecast.

92. If the actual TOP costs are greater or less than the $27.5 million, the TOP true up account will correct the difference in the next forecast proceeding.

93. Salmon argues that the forecast should be at or near $50.3 million in light of FERC actions which occurred after the close of hearing. Salmon argue that the uncertainty that existed regarding suspension of TOP costs at the time the stipulation was executed has largely been eliminated due to the two orders issued by FERC in December 1990.

94. Salmon submits that the TOP forecast for this ACAP period should be at least between $43.9 million and $53.3 million. Salmon contends that the uncertainty over the amount of the TOP costs is now based primarily upon the "timing" of FERC action on the El Paso rate case settlement.

95. While our inclination is to support the stipulation number reached by a diverse group of parties, we are troubled by the arguments raised by Salmon.

96. The parties have convinced us in their comments to the proposed decision that the $27.5 million forecast is reasonable in light of FERC's approval of the El Paso Settlement.

97. The stipulation specifically calls for 90 percent of any variation between noncore transportation revenues, excluding those revenues amortizing balances in existing balancing accounts, and the adopted noncore revenue requirement, excluding balances of

existing balancing accounts, be placed in an interest bearing balancing account.

98. The stipulation calls for the 90 percent balancing account to become effective on the date that the rate change resulting from this decision becomes effective. Further, it provides for the 90 percent balancing account to remain in effect until the implementation of rates resulting from PG&E's next cost allocation proceeding, currently estimated to be Spring 1992.

99. PG&E asserts that agreement would have been impossible, given the disparate litigation positions and the uncertainties involved, without the 90 percent balancing account for noncore transportation revenues being incorporated into the Stipulation as a protection mechanism against forecasting uncertainties.

100. Both DRA and TURN, representatives of California ratepayers, support the 90 percent balancing account as a necessary element of the overall stipulation. Both parties argue that given the uncertain oil market, and the joint desire of PG&E, TURN and DRA to resolve the issues in this ACAP, including the issue of negligible discounting due to high oil prices, the 90 percent balancing account is fair and reasonable given the evidence in this case.

101. CIG et al. believes the Commission should not adopt the 90 percent balancing account for this ACAP period because of its conflict with the 75 percent balancing account protection adopted as a rule for the new gas industry structure due to be implemented August 1, 1991 pursuant to D.90-09-089.

102. We must examine the 90 percent balancing account in the context of which it arose in this proceeding. The issue really is whether we are so troubled by the 90 percent balancing account that we want to change what the parties describe as one of the key elements of a stipulation supported by diverse interests.

103. CIG et al.'s arguments that there is no record to support the 90 percent balancing account are simply wrong. Testimony of

the panel members for PG&E, DRA, and TURN in support of the entire stipulation given on the last day of hearings explained the parties' rationale for agreeing to a 90 percent balancing account. Prior to negotiating the stipulation, PG&E requested 100 percent balancing account treatment for noncore transportation revenues in its supplemental testimony. (Exhibit 2.) DRA and TURN opposed this in their testimony (Exhibits 9 and 14).

104. We do not believe it is necessary in this case to substitute our judgment for that of such a diverse group of stipulating parties. Clearly, the 90 percent treatment was thought to be a better approach given the circumstances that arose during this proceeding, particularly the Gulf War.

105. Changing the 90 percent balancing account provision goes beyond mere "tinkering" with the decision, and would deprive the parties of a major benefit of their bargain.

106. We believe an adequate record has been developed in this proceeding to allow us to make a finding that the stipulation is in the public interest and will be adopted in its entirety.

107. We have acknowledged in prior decisions the strong public policy in California favoring settlements and the propriety of settlement in utility matters.

108. If our goal truly is to encourage settlements or stipulations, then we must resist the temptation to alter the results of a good faith negotiation process unless the public truly will be harmed by the agreement.

109. Despite the arguments of CIG et al. regarding the balancing account issue, we find the public interest is well served by the stipulation before us today.

110. PG&E, DRA, and TURN all propose different methods for allocating revenues from long-term contracts. At hearing, three contracts were at issue: Mojave Cogeneration, C&H Sugar and Luz Solar Partners. Since the close of hearing, Commission Resolutions G-2930 and G-2932 rejected both the C&H Sugar and the Luz Solar

Partners' contracts. Therefore, here we will only be addressing the appropriate allocation of the Mojave Cogeneration contract revenues.

111. PG&E proposes to treat revenues from Commission-approved long-term gas transportation contracts as a credit to base revenues and to allocate that credit to all remaining customers on the basis of average year throughput.

112. DRA believes that the Mojave Cogeneration contract should not be treated as a base revenue credit because it is not an EOR contract. DRA argues that long-term, non-EOR contracts should be treated as revenue shortfalls.

113. However, both DRA and PG&E agree that whether it is a credit or shortfall, it should be recovered from all other customers on an equal cents per therm basis.

114. TURN disagrees with the equal cents per therm proposal of both PG&E and DRA, believing it to be the wrong allocation method for the Mojave Cogeneration contract.

115. TURN argues that the Mojave contract is more akin to the long-term EOR contracts approved by the Commission because it is an anti-bypass contract. TURN also cites D.87-05-046 for authority for its view that because of Mojave's similarity to EOR contracts, the appropriate allocation mechanism is that the revenues should be treated as incremental and credited back to other customers based on an equal percentage of base revenues plus pipeline demand charges.

116. CIG et al. dispute that long-term non-EOR contracts (like Mojave) can be likened to EOR contracts. So long as the allocation is done on an equal cents per therm basis, CIG et al. are indifferent as to whether those revenues are treated as shortfalls or credits.

117. We agree with DRA, PG&E, and CIG et al. that revenue allocation on an equal cents per therm basis for the Mojave

Cogeneration contract is the most appropriate and consistent with D.87-05-046. The Mojave Contract is not an EOR contract.

118. As to the debate between PG&E and DRA over the revenue credit vs. shortfall issue, we find this argument to be "much ado about nothing" in that both parties agree there is no practical difference in result from their two theories. We agree with PG&E that its revenue credit approach is easier to implement.

119. PG&E is proposing a change from the current system of establishing rates on a monthly basis based on the actual average UEG rate lagged by 60 days to a rate based on the adopted UEG/Cogeneration cost allocation and throughput forecast.

120. CCC opposes PG&E's proposal in its entirety while DRA is opposed unless the problems created for Standard Offer 4 (SO4) Payment Option 3 cogenerators is resolved.

121. CCC disagrees with PG&E that it is appropriate to "solve a problem" for two-thirds of power purchased while creating a problem for the remaining one-third.

122. CCC believes it is inappropriate for PG&E to refer to the elimination of the CSA and undercollection of revenues in support of its proposal, arguing that PG&E did not explicitly state such arguments in its testimony.

123. PG&E has more fully developed the record in support of its proposal in this year's ACAP and all parties had an adequate opportunity to examine, attack, or propose alternatives. We believe that PG&E's proposal will have benefits for a significant number of cogenerators as well as for PG&E itself.

124. We reject CCC's argument that PG&E improperly argued protection of its revenue requirement in support of the switch to forecasted rates because it had not been developed in testimony.

125. In last year's ACAP decision, D.90-04-021, we ordered PG&E to discontinue entries to the CSA account. We also deferred recovery of the existing balance until this proceeding in order to allow for a detailed audit of the transactions in the account.

126. There is now general agreement that PG&E is entitled to recover some amount from the now defunct CSA. The update exhibit lists the amount of $1,106,000 (Ex. 28) while DRA's reply brief uses a figure of $1,078,905. DRA explains its figure of $1,078,905.

127. In light of the fact that DRA's, witness did not testify to any irregularities in her audit report, we are inclined to adopt PG&E's figure. Given the dollars involved, we find the conditions recommended by DRA and CCC to be unnecessary and burdensome.

128. The core-elect Purchased Gas Account is currently overcollected in the amount of $46,694,000.

129. If the core-elect Purchased Gas Account is amortized in core subscription rates during the ACAP period, the core subscription rate may appear cheaper relative to the rates that gas marketers will charge under the new noncore procurement rules effective August 1, 1991.

130. It is reasonable to order PG&E to refund the overcollection back to its core-elect customers because of the upcoming gas industry restructuring.

131. It is reasonable to allow PG&E to credit customer accounts rather than issue refund checks in order to avoid administrative expense.

132. It is reasonable to allow PG&E 120 days from the effective date of its revised tariff schedules to implement the refund.

133. TURN's request for eligibility was timely filed and addresses all four elements required by Rule 76.54(a) of the Commission's Rules of Practice and Procedure.

134. TURN represents the interests of individual residential customers not otherwise adequately represented in this proceeding who, as individuals, have a small economic interest in comparison to the costs of effective individual participation.

135. TURN has demonstrated that its participation in this proceeding would pose a significant financial hardship under Rule 76.52(f) and Rule 76.54(a)(1).

Conclusions of Law

1. We should waive Rule 51.6(c) of the Rules of Practice and Procedure because the goals of the settlement rules have been met by allowing all parties an opportunity for adequate cross-examination on the stipulation and underlying testimony.

2. We should not give the stipulation any precedential weight in any future PUC proceeding.

3. We should not assume that the numbers agreed upon in the stipulation are intended to have a relationship to each other.

4. We should adopt the stipulation approach as to oil prices i.e. that oil prices will be high enough that only a minimal discounting will occur.

5. We should adopt the stipulation's core WACOG of $2.23 per Dth and noncore WACOG of $2.52 per Dth.

6. We should adopt the following stipulation forecasts: 17.5 MMDth of G-P2B throughput, 138.3 MMDth of G-IND throughput, and 9.1 MMDth of Industrial GC-2 throughput because they are undisputed numbers.

7. We should adopt 23.9 MMDth as a forecast for Cool Water throughput because it was agreed to in the stipulation.

8. We should adopt 63 MMDth of cogeneration demand on rate schedule G-COG and 6.6 MMDth for demand under GC-2 contracts because no parties challenged these numbers.

9. We should adopt the following undisputed throughput forecasts: 1.1 MMDth for Steam Heat, 50.6 MMDth for EOR, and .1 MMDth for Industrial Interdepartmental.

10. We should adopt a forecast of 146.3 MMDth for UEG throughput, which assumes 18.2 MMDth of curtailment because it was agreed to in the stipulation.

11. We should adopt the stipulation curtailment level of 20 MMDth, all occurring in Priority Class P-5 because it is a compromise reached in the stipulation.

12. We should adopt PG&E's original forecast of 13.7 MMDth of wholesale throughput because no party disputed the figure.

13. We should adopt a residential throughput forecast of 217.2 MMDth and a commercial throughput forocast of 90.6 MMDth because they were agreed on in the stipulation.

14. The following throughput forecasts should be adopted: .2 MMDth for Core Interdepartmental, 1.4 MMDth for PG&E UEG startup fuel, 8.2 MMDth for Gas Department use, 17.5 MMDth for LAUF.

15. We should adopt a cold year throughput for wholesale customers of 14.6 MMDth because it is the compromise reached in the stipulation.

16. We should adopt the other cold year throughput numbers as set forth in the stipulation because they are undisputed.

17. We should adopt a cold year curtailment forecast of 37 MMDth because it is a reasonable compromise of the parties' original positions.

18. We should adopt an interutility throughput forecast of 50 MMDth because it was agreed to in the stipulation.

19. We should adopt an additional 2.1 cents per Dth to be incorporated into the forecast interutility rate because of an increase in interutility transport rates to collect gas gathering costs.

20. We should lower the balance in the allowance for doubtful accounts within the CFA debt service account to 5.4 percent of the outstanding loan portfolio balance as of the effective date of this decision.

21. We should decrease the NSRA balance by $4.535 million because it is recommended by the stipulation.

22. The EOR balancing account should be decreased by $319,222 because it is recommended by the stipulation.

23. We should update the PGT refund by $6.8 million to reflect the amount actually receiving by PG&E.

24. We should not include the balance in the NGV memorandum account in the revenue requirement for the ACAP test period based on the recommendation of the stipulating parties.

25. The RD&D adjustment of $1.008 million should be allocated $728,000 to the core and $352,000 to the noncore.

26. We should adopt PG&E proposal to consolidate several balancing accounts listed in Finding of Fact 68.

27. We should adopt a brokerage fee credit of $11,810,000 subject to balancing account treatment for this ACAP period because Phase 2 is not yet resolved.

28. We should adopt the following discount factors: Rate schedule G-IND excluding Cool Water 98 percent; rate schedule G-P2B, 97 percent; and rate schedule G-COG, 99 percent. We should adopt these figures because of the continuing uncertainties regarding oil prices as a result of the Gulf war.

29. We should adopt the pricing for the Cool Water facility agreed to in the stipulation.

30. We should adopt the stipulated cost allocation as set forth in Exhibit 27 (Appendix D).

31. We should adopt the stipulation proposal to reduce the residential tier differential because it reflects the consensus of the parties.

32. We should adopt PG&E's proposal to change the calculation of the LIRA credit because no party opposed it.

33. We should adopt direct-billed take-or-pay costs of $27.5 million for this ACAP period.

34. The 90 percent balancing account should convert automatically to a 75 percent balancing account on April 1, 1992.

35. We should adopt the 90 percent balancing account for noncore transportation revenues because to alter it would deprive the stipulating parties of a major benefit of their bargain.

36. We should adopt the stipulation because it is in the public interest.

37. We should adopt PG&E's proposal to treat revenues from the Mojave Cogeneration contract as a credit to base revenues and to allocate it all to customers on an equal cents per therm basis.

38. We should adopt PG&E's proposal to change cogeneration rates to a forecast basis because cogenerators who produce two-thirds of power purchased will now have a consistent forecast methodology for both their costs and revenues.

39. We should allow PG&E to recover $1,106,000 from the Cogeneration Shortfall Account.

40. PG&E should refund the core-elect PGA overcollection to the core-elect customers during the 1990-91 ACAP test period by crediting those customers accounts. PG&E will be allowed 120 days from the effective date of its revised tariff schedules to implement a refund.

41. TURN should be found eligible under Article 18.7 of our rules to claim compensation for its participation in its proceeding.

42. The determination that TURN has met its burden of showing that its participation in this proceeding would pose a significant financial hardship should carry over to TURN's participation in other proceedings in 1991.

43. This order should be made effective today in order to get the new rates into effect as soon as possible.

INTERIM ORDER

IT IS ORDERED that:

1. Pacific Gas and Electric Company shall file, in accordance with General Order 96-A, tariff changes which implement the rate changes adopted in this proceeding, and which are shown in Appendix C to this decision, using the revenue requirement presented in Appendix B. This tariff filing shall also reflect the updated baseline quantities effective May 1, 1990.

2. The revised tariff schedules shall be filed on or after the effective date of this decision and at least 3 days prior to their effective date.

3. The Stipulation attached as Appendix D is approved in its entirety.

4. PG&E shall institute a refund of the core-elect Purchase Gas Account in compliance with the discussion in this decision. The refund shall be implemented within 120 days from the effective date of its revised tariff schedules.

5. Toward Utility Rate Normalization (TURN) is eligible to claim compensation for its participation in this proceeding.

6. The determination that TURN has met its burden of showing that its participation in this proceeding would pose a significant financial hardship shall carry over to TURN's participation in other proceedings in 1991.

This order is effective today.

Dated May 8, 1991, at San Francisco, California.

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

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

Neal J. Shulman

NEAL J. SHULMAN, Executive Director

pb

APPENDIX A

Applicant: Roger J. Peters, Mark R. Huffman, and Barbara S. Benson, Attorneys at Law, for Pacific Gas and Electric Company.

Interested Parties: Messrs. Chickering & Gregory by C. Hayden Ames, Attorney at Law, for Messrs. Chickering & Gregory, P.C.; Barkovich & Yap by Barbara Barkovich, for Barkovich & Yap; Patrick J. Bittner, Attorney at Law, for California Energy Commission; Jerry R. Bloom, Lynn M. Haug, and Morrison & Foerster, by Douglas R. Ware, Attorneys at Law, for California Cogeneration Council; Beth Bowman, for San Diego Gas & Electric Company; Messrs. Greve, Clifford, Diepenbrock & Paras by Matthew V. Brady, Attorney at Law, and Messrs. Grueneich, Ellison & Schneider by Christopher T. Ellison and Barry H. Epstein, for California Department of General Services; Ariel Pierre Calonne, Attorney at Law, for City of Palo Alto; Messrs. Armour, Goodin, Schlotz & Mac Bride, by Regina M. De Angelis, Attorney at Law, for Kelco Division of Merck & Company; Philip Di Virgilio, for Destech Energy Incorporated; Karen Edson, for KKE & Associates; Michel Peter Florio and Joel R. Singer, for Toward Utility Rate Normalization (TURN); Norman J. Furuta, Attorney at Law, for Department of the Navy; Annette Gilliam, Richard K. Durant & Frank J. Cooley, for Southern California Edison Company; Steve Harris, for Transwestern Pipeline Company; Adrian Hudson, for California Gas Producers Association; Messrs. Brady & Berliner by John W. Jimison and Tom Beach, Attorneys at Law, for Canadian Producer Group and Luz Partnership Management; Messrs. Luce, Forward, Hamilton & Scripps, by John W. Leslie, Attorney at Law, appearing for Salmon Resources Limited; William Marcus and Jeffrey Nahigian, for JBS Energy Incorporated; Patrick Mc Donnell, for SunPacific Energy; Messrs. Squire, Sanders & Dempsey, by Keith R. Mc Crea and Michael T. Mishkin, Attorneys at Law, for California Industrial Group, California Manufacturers Association, and California League of Food Processors; Ronald G. Oechsler, for Recon Research Corporation; Thomas O'Rourke, for Southwest Gas Corporation; Patrick J. Power, Attorney at Law, for City of Palo Alto; Raul Premo, for Chevron U.S.A.; John D. Quinley, for Cogeneration Service Bureau; E.R. Island and David B. Follett, Attorneys at Law, and Earl K. Takemura, for Southern California Gas Company; Morse, Richard, Weisenmiller & Associates, by Robert Weisenmiller, for Morse, Richard & Associates; Randolph L. Wu and Phyllis Huckabee, for El Paso Natural Gas Company; E. D. Yates, for California League of Food Processors; Jim L. Evans, Senior Marketing Representative, for Petro-Canada Resources Inc.; Messrs. Ater, Wynne, Hewitt, Dodson & Skerritt, by Paul Kauffman, Attorney at Law, for Cogenerators of Southern California; Jerry Mc Namara, for Alberta Petroleum Marketing Commission; Melissa Metzler, for Barakat & Chamberlin, Inc.; Donald W. Schoenbeck, for RCS, Inc.; and Thomas A. Tribble, P.E., J.D., for Regents-University of California.

Division of Ratepayer Advocates: John S. Wong, Attorney at Law, Larry Klapow, and Natalie Walsh.

(END OF APPENDIX A)

TABLE 1

PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED GAS DEMAND

Forecast Period: April 1, 1991 to March 31, 1992

THROUGHPUT TYPE	GAS DEMAND (Mdth)
Residential	217,243
Commercial Core	90,639
Industrial (incl. GC2)	164,900
Steam Heat	1,086
UEG-PG&E (incl. start-up)	165,883
UEG-Edison	23,900
Cogeneration (excl. GC2)	63,000
Cogeneration	6,600
EOR Cogeneration	28,447
EOR Steaming	22,138
Company Use	8,174
Unaccounted For	17,543
Wholesale	13,738
Interdepartmental	314
Interutility	50,000
TOTAL GAS DEMAND	873,605

TABLE 2

PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED DEMAND FORECAST BY PRIORITY

Forecast Period: April 1, 1991 to March 31, 1992

PRIORITY	DEMAND FORECAST (Mdth)
P-1	333,448
P-2A	14,625
P-2B	17,500
P-3A	98,047
P-3B	68,785
P-4	99,844
P-5	241,356
TOTAL	873,605

TABLE 3A

PACIFIC GAS AND ELECTRIC COMPANY

ADOPTED DEMAND, CURTAILMENTS AND SUPPLY FORECAST BY CUSTOMER CLASS

Forecasted Period: April 1, 1991 to March 31, 1992

SCHEDULE AND CATEGORY	PRIORITY	DEMAND FORECAST (MDTH)	CURTAIL-MENTS (MDTH)	SUPPLY FORECAST (MDTH)
RESIDENTIAL	P-1	217,243	0	217,243
COMMERCIAL G1-NR1	P-1	72,973	0	72,973
COMMERCIAL G-NR2C	P-1	6,070	0	6,070
COMMERCIAL G-NR3N	P-1	19	0	19
COMMERCIAL G-NR3T	P-1	74	0	74
COMMERCIAL G-NR1	P-2A	2,257	0	2,257
COMMERCIAL G-NR2C	P-2A	9,105	0	9,105
COMMERCIAL G-NR3N	P-2A	29	0	29
COMMERCIAL G-NR3T	P-2A	112	0	112
TOTAL COMMERCIAL		90,639	0	90,639
INDUSTRIAL G-P2BC	P-2B	12,251	0	12,251
INDUSTRIAL G-P2BN	P-2B	3,393	0	3,393
INDUSTRIAL G-P2BT	P-2B	1,856	0	1,856
TOTAL P2B		17,500	0	17,500
INDUSTRIAL G-INDC	P-3B	19,067	0	19,067
INDUSTRIAL G-INDN	P-3B	9,261	0	9,261
INDUSTRIAL G-INDT	P-3B	17,311	0	17,311
INDUSTRIAL GC2-C	P-3B	1,201	0	1,201
INDUSTRIAL GC2-N	P-3B	577	0	577
INDUSTRIAL GC2-T	P-3B	1,225	0	1,225
INDUSTRIAL G-INDC	P-4	38,712	0	38,712
INDUSTRIAL G-INDN	P-4	18,803	0	18,803
INDUSTRIAL G-INDT	P-4	35,146	0	35,146
INDUSTRIAL GC2-C	P-4	2,439	0	2,439
INDUSTRIAL GC2-N	P-4	1,171	0	1,171
INDUSTRIAL GC2-T	P-4	2,487	0	2,487
TOTAL G-IND & INDUSTRIAL GC2		147,400	0	147,400
COGENERATION G-COGC	P-3A	31,497	0	31,497
COGENERATION G-COGN	P-3A	12,265	0	12,265
COGENERATION G-COGT	P-3A	19,238	0	19,238
COGENERATION GC2-C	P-3A	3,300	0	3,300
COGENERATION GC2-N	P-3A	1,293	0	1,293
COGENERATION GC2-T	P-3A	2,007	0	2,007
TOTAL COGENERATION		69,600	0	69,600
EOR COGENERATION C	P-3A	8,534	0	8,534
EOR COGENERATION N	P-3A	1,707	0	1,707
EOR COGENERATION T	P-3A	18,206	0	18,206
EOR STEAMING C	P-5	0	0	0
EOR STEAMING N	P-5	2,214	182	2,032
EOR STEAMING T	P-5	19,924	1,633	18,291
TOTAL EOR		50,585	1,815	48,770

TABLE 38

PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED DEMAND, CURTAILMENTS AND SUPPLY FORECAST BY CUSTOMER CLASS

Forecasted Period: April 1, 1991 to March 31, 1992

SCHEDULE AND CATEGORY		PRIORITY	DEMAND-FORECAST (MDTH)	CURTAIL-MENTS (MDTH)	SUPPLY FORECAST (MDTH)
STEAM HEAT	G-NCT	P-4	1,086	0	1,086
UEG-PG&E		P-5	164,438	18,178	146,260
UEG-PG&E	START-UP	P-2A	1,445	0	1,445
UEG-SCE	G-NCT	P-3B	19,120	0	19,120
UEG-SCE	G-NCT	P-5	4,780	0	4,780
TOTAL UEG			189,783	18,178	171,605
MISC COMPANY USE		P-1	8,174	0	8,174
UNACCOUNTED FOR		P-1	17,543	0	17,543
TOTAL RETAIL			809,553	19,993	772,060
COALINGA	G-WRT	P-1	170	0	170
CP NATIONAL	G-WRT	P-1	76	0	76
PALO ALTO	G-WRT	P-1	2,722	0	2,722
SOUTHWEST	G-WRT	P-1	8,173	0	8,173
COALINGA	G-WRT	P-2A	33	0	33
PALO ALTO	G-WRT	P-2A	671	0	671
SOUTHWEST	G-WRT	P-2A	973	0	973
PALO ALTO	G-WRT	P-3B	336	0	336
SOUTHWEST	G-WRT	P-3B	584	0	584
TOTAL WHOLESALE			13,738	0	13,738
INTERDEPARTMENTAL	C	P-1	211	0	211
INTERDEPARTMENTAL	C	P-3B	103	0	103
TOTAL INTERDEPARTMENTAL			314	0	314
INTERUTILITY			50,000	0	50,000
TOTAL			873,605	19,993	836,112

TABLE 4

PACIFIC GAS AND ELECTRIC COMPANY
GAS PROCUREMENT RATES

Forecast Period: April 1, 1991 to March 31, 1992

	CORE	CORE-ELECT [1]	NONCORE [1]	WHOLESALE [1]	TOTAL
SALES VOLUMES (Mth) [2]	3,091,237	2,996,113	290,520	137,390	6,515,260
WACOG PRICE ($/therm)	0.22300	0.22300	0.25200	0.22300	0.22429
SUBTOTAL REVENUE (000's)	689,346	668,133	73,211	30,638	1,461,328
CORE PGA REVENUE	22,162				22,162
CORE-ELECT PGA REVENUE [3]		0		0	0
SUBTOTAL REVENUE	711,508	668,133	73,211	30,638	1,483,490
F&U RATE [4]	0.00899	0.00899	0.00899	0.00709	0.00899
F&U	6,396	6,007	658	217	13,337
REVENUE	717,904	674,140	73,869	30,855	1,496,826
RATE BEFORE BROKERAGE FEES (a)	0.23224	0.22500	0.25427	0.22458	0.22974
BROKERAGE FEES		10,242	993	470	11,705
BROKERAGE FEE F&U		92	9	3	104
BROKERAGE FEES INC F&U		10,334	1,002	473	11,809
BROKERAGE FEE RATE (b)		0.00345	0.00345	0.00345	0.00345
FINAL PROCUREMENT RATE (a+b)	0.23224	0.22845	0.25772	0.22803	0.23319

[1] RATES MAY VARY DURING THE TEST PERIOD.
[2] SALES VOLUMES REFLECT SHRINKAGE AND STORAGE.
[3] ACCOUNT BALANCE IS $46,694. CUSTOMERS WILL BE REFUNDED PER THIS DECISION.
[4] WHOLESALE PAYS FRANCHISE FEES ONLY.

TABLE 5

PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED REVENUE REQUIREMENTS

Forecasted Period: April 1, 1991 to March 31, 1992

PROCUREMENT REVENUE REQUIREMENT	($000's)	
Total Core Procur. Revenue (incl Core-elect)	1,346,996	
Total Non-core Procurement Revenue	73,869	
Total Wholesale Procurement Revenue	28,793	
Brokerage Fees (incl. F&U)	11,809	
TOTAL PROCUREMENT REVENUE REQUIREMENT		1,461,468
TRANSPORTATION REVENUE REQUIREMENT		
Auth. gas margin		
Common distribution	276,945	
Demand related transmission	212,600	
Demand related storage	43,869	
Customer related	499,381	
Commodity related	10,145	
50% Adminstrative & General	88,634	
Franchise & Uncollectibles	10,208	
Less: Brokerage Fees	(11,810)	
Less: Other operating revenue	(9,149)	
Less: Long term contract revenue	(2,858)	
		1,117,964
Pipeline demand charges	176,496	
Add: F&U at 0.00895 *	1,580	
		178,076
Transition costs	27,500	
Add: F&U at 0.00893 *	245	
		27,745
EOR / Interutility Revenue Credit		(19,080)
DSM and RD&D Revenue Offset	1,080	
El Paso TOP Trueup	20,467	
Noncore Adjustments	3,092	
Gas Storage Carrying Cost	14,574	
Gas Fixed Cost Account	49,873	
Non-core Balancing/Tracking Accounts	(13,798)	
Core Company use and unaccounted for gas	26,252	
Non-core Company use and unaccounted for gas	35,589	
CFA Debt Service and Expense	2,628	
Gas Exploration and Development Account	50,000	
CPUC Fee	4,489	
Low Income Rate Assistance	1,961	
Add: F&U at 0.00897 *	1,759	
		197,966
TOTAL TRANSPORTATION REVENUE REQUIREMENT		1,502,672
NET REVENUE REQUIREMENT		2,964,140

* Composite rate based on the following:
0.00899 = F&U Other than Wholesale factor
0.00709 = Franchise Wholesale factor

TABLE 6

PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED COSTS

ForecastedForecasted Period: April 1, 1991 to March 31, 1992

	VOLUMES (Mth)	PRICE ($/th)	COSTS ($000's)	
Gas Supplies				
Core & Core-Elect	6,224,740	0.22300	1,388,117	
Noncore	290,520	0.25200	73,211	1,461,328
Gas Storage Carrying Cost				14,574
Brokerage Fee				11,705
Pipeline Demand Charges				
PGT-Canadian			92,081	
PGT Cost of Service			42,012	
El Paso			42,403	176,496
Transition Costs				
El Paso Take or Pay			27,500	
GEDA			50,000	77,500
CFA				
Debt Service			390	
Expense			2,238	2,628
Gas Dept Use & Unaccounted for				
Gas Department Use (Core)	32,510	0.22300	7,250	
Unaccounted for (Core)	69,760	0.22300	15,556	22,806
Gas Department Use (Noncore)	49,230	0.25200	12,406	
Unaccounted for (Noncore)	105,670	0.25200	26,629	39,035
CPUC Fee				4,489
LIRA A&G				1,961
Balancing/Tracking Accounts				
Core Purchased Gas Account				22,162
Core-elect Purchased Gas Account				(46,694)
Gas Fixed Cost Account				49,873
Noncore Accounts				
Enhanced Oil Recovery Account			(2,492)	
A&S Interutiliyt Balancing Account			(109)	
CFA Debt Service			(1,671)	
CFA Expense			344	
Noncore Transition Cost Account			(2,699)	
Cogeneration Shortfall Account			1,106	
LIRA Account			(8,277)	(13,798)
El Paso TOP Trueup				20,467
Noncore Adjustments				
Pipeline Demand Trueup			2,401	
Gas Storage Trueup			1,708	
Noncore Base Cost Adjustment			(193)	
1990 ACAP F&U Adjustment			(1,021)	
Earthquake Recovery Adjustment			486	
California Corporate Franchise Tax Adjustment			(289)	3,092
F&U				3,585
TOTAL COSTS				1,851,209

(END OF APPENDIX B)

TABLE 1

PACIFIC GAS AND ELECTRIC COMPANY
ADJUSTED ALLOCATION FACTORS BY CUSTOMER CLASS

Forecast Period: April 1, 1991 to March 31, 1992

ALLOCATION INDEX	ALLOCATION FACTOR	RESIDENTIAL	SM COML G-NR1 SUMMER	G-NR1 WINTER	G-NGV SUMMER	G-NGV WINTER	LG COML G-NR2 SUMMER	G-NR2 WINTER	P2B NC G-P2B	IND G-NCT	UEG G-UEG	COGEN G-COG	WHOLESALE G-WRT
EMBEDDED COST OF SERVICE *													
a	Avg. Yr. Throughput	0.30638	0.10834	0.00000	0.00000	0.00000	0.02207	0.00000	0.02401	0.22063	0.20667	0.09250	0.01941
b	Weighted Customers	0.90179	0.07613	0.00000	0.00000	0.00000	0.00202	0.00000	0.00125	0.01290	0.00247	0.00301	0.00043
c	Pk. Seas. Cold Yr. Thrpt.	0.42577	0.12324	0.00000	0.00000	0.00000	0.02531	0.00000	0.02007	0.19809	0.11099	0.07256	0.02396
d	Cold Yr NC Pk No Dist Thrpt	0.64018	0.17262	0.00000	0.00000	0.00000	0.03551	0.00000	0.01650	0.11045	0.00000	0.02474	0.00000
e	Cold Yr. Throughput	0.33861	0.11452	0.00000	0.00000	0.00000	0.02338	0.00000	0.02315	0.21295	0.17835	0.08919	0.01984
f	Base Revenues	0.66175	0.11168	0.00000	0.00000	0.00000	0.01690	0.00000	0.01183	0.09983	0.05709	0.03510	0.00582
g	Revenues less Wholesale	0.66563	0.11233	0.00000	0.00000	0.00000	0.01700	0.00000	0.01190	0.10042	0.05743	0.03530	0.00000
h	Rev. plus Pipeline Dmd. Chg.	0.61819	0.11206	0.00000	0.00000	0.00000	0.01777	0.00000	0.01336	0.11509	0.07344	0.04239	0.00771
i	Avg Yr. Thrpt. less Shrnkg.	0.30638	0.10834	0.00000	0.00000	0.00000	0.02207	0.00000	0.02401	0.22063	0.20667	0.09250	0.01941
j	Avg Yr. Thrpt.- NC	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.04263	0.39173	0.36694	0.16423	0.03447
k	Customers, Core	0.92025	0.07769	0.00000	0.00000	0.00000	0.00206	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
l	Customers, NC & Whsl	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.06236	0.64325	0.12309	0.14996	0.02134
m	A&G Allocation **	0.30922	0.10935	0.00000	0.00000	0.00000	0.02228	0.00000	0.02423	0.22268	0.20858	0.09335	0.01031
n	CYNC Pk, NC	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.10878	0.72809	0.00000	0.16313	0.00000
BALANCING ACCOUNTS AND FORECASTED PERIOD COSTS													
	Non-LIRA Requirements	2,050,021	0	0	0	0	0	0	0	0	0	0	142,383
	Adjusted Deliveries (Incl. Shrinkage)	2,247,060	0	794,612	0	0	0	161,876	176,079	1,618,153	1,515,748	678,388	
	Unadjusted Deliveries:	2,172,460	307,820	458,930	234	317	62,290	93,871	175,160	1,725,550	1,462,600	695,570	137,390
1	Cts/Therm - All:	0.30638	0.00000	0.10834	0.00000	0.00000	0.00000	0.02207	0.02401	0.22063	0.20667	0.09250	0.01941
2	Cts/Therm - No Cog, UEG, Whl:	0.44961	0.00000	0.15899	0.00000	0.00000	0.00000	0.03239	0.03523	0.32377	0.00000	0.00000	0.00000
3	Cts/Therm - Core Only:	0.70143	0.00000	0.24804	0.00000	0.00000	0.00000	0.05053	0.00000	0.00000	0.00000	0.00000	0.00000
4	Cts/Therm - No Whlsl:	0.31244	0.00000	0.11049	0.00000	0.00000	0.00000	0.02251	0.02448	0.22500	0.21076	0.09433	0.00000
5	Percent/Embedded Cost + pipe d:	0.62152	0.11270	0.00000	0.00000	0.00000	0.01789	0.00000	0.01322	0.11369	0.07172	0.04172	0.00754
6	Cold-year Deliveries:	0.33861	0.00000	0.11452	0.00000	0.00000	0.00000	0.02338	0.02315	0.21295	0.17835	0.08919	0.01984
7	Peak-season, cold-yr Deliveries:	0.42577	0.00000	0.12324	0.00000	0.00000	0.00000	0.02531	0.02007	0.19809	0.11099	0.07256	0.02396
8	Cts/Therm - No GC-2:	0.31332	0.00000	0.11080	0.00000	0.00000	0.00000	0.02257	0.02455	0.21245	0.21135	0.08510	0.01985
9	Cts/Therm - Noncore Only:	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.04263	0.39173	0.36694	0.16423	0.03447
10	Cts/Therm - Noncore Except Whls:	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.04415	0.40572	0.38004	0.17009	0.00000
11	Cts/Therm - All - Shrinkage:	0.29792	0.04221	0.06293	0.00003	0.00004	0.00854	0.01287	0.02402	0.23663	0.20057	0.09539	0.01884
12	Cts/Therm - All - CPUC Fee:	0.39870	0.05543	0.08264	0.00004	0.00006	0.01128	0.01699	0.03215	0.27506	0.00000	0.12765	0.00000
13	Cts/Therm - UEG and Cogen Only:	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.69082	0.30918	0.00000
14	Cts/Therm - No LIRA,UEG,COG,Whl:	0.42702	0.00000	0.16552	0.00000	0.00000	0.00000	0.03372	0.03668	0.33706	0.00000	0.00000	0.00000
15	Cts/Therm - No Core, COG, Whl:	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.07121	0.65443	0.00000	0.27436	0.00000
16	Index 6, Noncore only:	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.04422	0.40680	0.34070	0.17038	0.03790
17	Index 7, Noncore only:	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.04716	0.46536	0.26073	0.17046	0.05629
18	Percent/Embedded Cost:	0.66696	0.11241	0.00000	0.00000	0.00000	0.01700	0.00000	0.01163	0.09775	0.05459	0.03409	0.00556
19	Index 7, CORE only:	0.74135	0.00000	0.21458	0.00000	0.00000	0.00000	0.04406	0.00000	0.00000	0.00000	0.00000	0.00000
20	Pct./Tot. Fixed Costs, NC Only	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.05223	0.44510	0.30669	0.16428	0.03170
21	Index 18, NC only:	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.05710	0.48004	0.26810	0.16743	0.02733

* No Summer/Winter differentiation. Factors derived from negotiated stipulation.

TABLE 2

PACIFIC GAS AND ELECTRIC COMPANY
UNADJUSTED ALLOCATION FACTORS BY CUSTOMER CLASS

Forecast Period: April 1, 1991 to March 31, 1992

ALLOCATION INDEX	ALLOCATION FACTOR	RESIDENTIAL	SM COML G-NR1 SUMMER	G-NR1 WINTER	G-NGV SUMMER	G-NGV WINTER	LG COML G-NR2 SUMMER	G-NR2 WINTER	P2B NC G-P2B	IND G-NCT	UEG G-UEG	COGEN G-COG	WHOLESALE G-WRT
EMBEDDED COST OF SERVICE *													
a	Avg. Yr. Throughput	0.29897	0.10572	0.00000	0.00000	0.00000	0.02154	0.00000	0.02415	0.23793	0.20167	0.09108	0.01894
b	Weighted Customers	0.90179	0.07613	0.00000	0.00000	0.00000	0.00202	0.00000	0.00125	0.01290	0.00247	0.00301	0.00043
c	Pk. Seas. Cold Yr. Thrpt.	0.41613	0.12045	0.00000	0.00000	0.00000	0.02473	0.00000	0.02023	0.21497	0.10847	0.07160	0.02342
d	Cold Yr NC Pk Mo Dist Thrpt	0.63199	0.17041	0.00000	0.00000	0.00000	0.03505	0.00000	0.01679	0.12111	0.00000	0.02464	0.00000
e	Cold Yr. Throughput	0.33071	0.11185	0.00000	0.00000	0.00000	0.02284	0.00000	0.02331	0.22983	0.17418	0.08790	0.01938
f	Base Revenues	0.65723	0.11029	0.00000	0.00000	0.00000	0.01662	0.00000	0.01195	0.10779	0.05577	0.03466	0.00568
g	Revenues less Wholesale	0.66099	0.11092	0.00000	0.00000	0.00000	0.01671	0.00000	0.01202	0.10840	0.05609	0.03486	0.00000
h	Rev. plus Pipeline Dmd. Chg.	0.61321	0.11050	0.00000	0.00000	0.00000	0.01745	0.00000	0.01348	0.12424	0.07173	0.04184	0.00753
i	Avg Yr. Thrpt. less Shrnkg.	0.29897	0.10572	0.00000	0.00000	0.00000	0.02154	0.00000	0.02415	0.23793	0.20167	0.09108	0.01894
j	Avg Yr. Thrpt.- NC	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.04209	0.41468	0.35148	0.15874	0.03302
k	Customers, Core	0.92025	0.07769	0.00000	0.00000	0.00000	0.00206	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
l	Customers, NC & Whsl	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.06236	0.64325	0.12309	0.14996	0.02134
m	A&G Allocation **	0.30168	0.10668	0.00000	0.00000	0.00000	0.02173	0.00000	0.02437	0.24008	0.20349	0.09190	0.01006
n	CYNC Pk, NC	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.10332	0.74511	0.00000	0.15157	0.00000
BALANCING ACCOUNTS AND FORECASTED PERIOD COSTS													
	Non-LIRA Requirements	2,050,021	0	0	0	0	0	0	0	0	0	0	0
	Adjusted Deliveries (Incl. Shrinkage)	2,247,060	0	794,612	0	0	0	161,876	181,525	1,800,309	1,515,748	685,241	142,383
	Unadjusted Deliveries:	2,172,460	307,820	458,930	234	317	62,290	93,871	0	1,919,795	1,462,600	702,596	137,390
1	Cts/Therm - All:	0.29846	0.00000	0.10554	0.00000	0.00000	0.00000	0.02150	0.02411	0.23912	0.20133	0.09102	0.01891
2	Cts/Therm - No Cog, UEG, Whl:	0.43335	0.00000	0.15324	0.00000	0.00000	0.00000	0.03122	0.03501	0.34719	0.00000	0.00000	0.00000
3	Cts/Therm - Core Only:	0.70143	0.00000	0.24480	0.00000	0.00000	0.00000	0.05053	0.00000	0.00000	0.00000	0.00000	0.00000
4	Cts/Therm - No Whlsl:	0.30422	0.00000	0.10758	0.00000	0.00000	0.00000	0.02192	0.02458	0.24373	0.20521	0.09277	0.00000
5	Percent/Embedded Cost + pipe d:	0.62152	0.11270	0.00000	0.00000	0.00000	0.01789	0.00000	0.01322	0.11369	0.07172	0.04172	0.00754
6	Cold-year Deliveries:	0.33861	0.00000	0.11452	0.00000	0.00000	0.00000	0.02338	0.02315	0.21295	0.17835	0.08919	0.01984
7	Peak-season, cold-yr Deliveries:	0.42577	0.00000	0.12324	0.00000	0.00000	0.00000	0.02531	0.02007	0.19809	0.11099	0.07256	0.02396
8	Cts/Therm - No GC-2:	0.30505	0.00000	0.10787	0.00000	0.00000	0.00000	0.02198	0.02464	0.23157	0.20577	0.08378	0.01933
9	Cts/Therm - Noncore Only:	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.04197	0.41624	0.35045	0.15843	0.03292
10	Cts/Therm - Noncore Except Whls:	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.04340	0.43041	0.36237	0.16382	0.00000
11	Cts/Therm - All - Shrinkage:	0.29685	0.04206	0.06271	0.00003	0.00004	0.00851	0.01283	0.00000	0.26233	0.19986	0.09601	0.01877
12	Cts/Therm - All - CPUC Fee:	0.39680	0.05516	0.08224	0.00004	0.00006	0.01122	0.01691	0.00000	0.30923	0.00000	0.12833	0.00000
13	Cts/Therm - UEG and Cogen Only:	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.68867	0.31133	0.00000
14	Cts/Therm - No LIRA,UEG,COG,Whl:	0.41096	0.00000	0.15929	0.00000	0.00000	0.00000	0.03245	0.03639	0.36090	0.00000	0.00000	0.00000
15	Cts/Therm - No Core, COG, Whl:	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.06806	0.67501	0.00000	0.25693	0.00000
16	Index 6, Noncore only:	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.04422	0.40680	0.34070	0.17038	0.03790
17	Index 7, Noncore only:	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.04716	0.46536	0.26073	0.17046	0.05629
18	Percent/Embedded Cost:	0.66696	0.11241	0.00000	0.00000	0.00000	0.01700	0.00000	0.01163	0.09775	0.05459	0.03409	0.00556
19	Index 7, CORE only:	0.74135	0.00000	0.21458	0.00000	0.00000	0.00000	0.04406	0.00000	0.00000	0.00000	0.00000	0.00000
20	Pct./Tot. Fixed Costs, NC Only	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.05223	0.44510	0.30669	0.16428	0.03170
21	Index 18, NC only:	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.05710	0.48004	0.26810	0.16743	0.02733

* No Summer/Winter differentiation. Factors derived from negotiated stipulation.

TABLE 3

PACIFIC GAS AND ELECTRIC COMPANY
COST ALLOCATION SUMMARY

Forecast Period: April 1, 1991 to March 31, 1992

	ALLOC INDEX	SYSTEM COST ($000)	CORE COST ($000)	NONCORE & CORE-ELECT ($000)	WHOLESALE COST ($000)
FORECAST PERIOD COSTS					
Commodity Related Base	a	10,145	4,431	5,517	197
Transmission Base	e	212,600	101,308	107,073	4,218
Storage Base	c	43,869	25,195	17,623	1,051
Distribution Base	d	276,945	234,935	42,010	0
Customer Base	b	499,381	489,364	9,803	214
50% Adminstrative and General	m	88,634	39,074	48,646	914
Other Operating Revenue	f	(9,149)	(7,231)	(1,865)	(53)
SUBTOTAL - Base (Margin)		1,122,424	887,076	228,807	6,540
EOR Credit	h	(12,187)	(9,116)	(2,977)	(94)
Interutility Transportation Service	e	(6,893)	(3,285)	(3,472)	(137)
Brokerage Fee: Procurement A&G	j	(5,298)	0	(5,115)	(183)
Brokerage Fee: Core Marketing	k	(6,389)	(6,389)	0	0
Brokerage Fee: Noncore Marketing	l	(123)	0	(120)	(3)
Long Term Contract Revenue	a	(2,858)	(1,248)	(1,554)	(55)
SUBTOTAL - Adjusted Base		1,088,676	867,038	215,569	6,069
Pipe Demand Charges	6	176,496	84,104	88,890	3,502
Pipeline Demand Trueup	16	2,401	0	2,310	91
Gas Storage Carrying Costs	7	14,574	8,370	5,855	349
Gas Storage Trueup	17	1,708	0	1,612	96
Take-or-Pay Transition Costs	1	27,500	12,012	14,954	534
Take-or-Pay Trueup	1	20,467	8,940	11,130	397
CFA Debt Service and Expense	2	2,628	1,685	943	0
Gas Exploration & Development Account	1	50,000	21,839	27,190	971
LUAF & CDU	11	61,841	26,252	34,424	1,165
CPUC Fee	12	4,489	2,537	1,952	0
LIRA A&G	14	1,961	1,228	733	0
RD&D Trueup - Core	19	728	728	0	0
RD&D Trueup - Noncore	17	352	0	332	20
Noncore Base Cost Adjustment	17	(193)	0	(182)	(11)
1990 ACAP F&U Adjustment	20	(1,021)	0	(989)	(32)
Corporate Franchise Tax Adjustment	21	(289)	0	(281)	(8)
Earthquake Recovery Adjustment	n	486	0	486	0
TOTAL - Forecasted Period Costs		1,452,804	1,034,733	404,928	13,143
				0	
AMORTIZATION OF BALANCING ACCOUNTS					
Gas Core Fixed Cost	3	49,873	49,873	0	0
Noncore Transition Cost	9	(2,699)	0	(2,606)	(93)
Enhanced Oil Recovery	5	(2,492)	(1,874)	(599)	(19)
A&S Interutility	6	(109)	(52)	(55)	(2)
CFA Debt Service and Expense	2	(1,327)	(851)	(476)	0
Core TOP	3	0	0	0	0
NGV	1	0	0	0	0
LIRA	14	(8,277)	(5,184)	(3,093)	0
COGEN Shortfall	13	1,106	0	1,106	0
TOTAL - Forecasted Acct Balances		36,075	41,913	(5,724)	(114)
F&U		13,793	9,962	3,734	96
TOTAL - Transport Revenue Requirement		1,502,672	1,086,607	402,939	13,125
ALLOCATION ADJUSTMENTS					
G-10 Allocated Employee Discount	18	969	772	192	5
GC-2 Shortfall		(7,941)	0	(10,253)	0
GC-2 Shortfall Allocated	8	7,941	3,547	4,236	158
LIRA Discount Benefits		(17,268)	(17,268)	0	0
LIRA Discount Expenses	14	17,268	10,814	6,454	0
TOTAL - Transport Costs		1,503,641	1,084,473	403,567	13,288

TABLE 4

PACIFIC GAS AND ELECTRIC COMPANY
RESIDENTIAL CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1991 to March 31, 1992

	ALLOC INDEX	SYSTEM COST ($000)	UNADJ ALLOC FACTOR	UNADJ COST ($000)	ADJ ALLOC FACTOR	ADJ COST ($000)
FORECAST PERIOD COSTS						
Commodity Related Base	a	10,145	0.29897	3,033	0.30638	3,108
Transmission Base	e	212,600	0.33071	70,309	0.33861	71,989
Storage Base	c	43,869	0.41613	18,255	0.42577	18,678
Distribution Base	d	276,945	0.63199	175,027	0.64018	177,294
Customer Base	b	499,381	0.90179	450,338	0.90179	450,338
50% Adminstrative and General	m	88,634	0.30168	26,739	0.30922	27,407
Other Operating Revenue	f	(9,149)	0.65723	(6,013)	0.66175	(6,054)
SUBTOTAL - Base (Margin)		1,122,424		737,688		742,761
EOR Credit	h	(12,187)	0.61321	(7,473)	0.61819	(7,534)
Interutility Transportation Service	e	(6,893)	0.33071	(2,280)	0.33861	(2,334)
Brokerage Fee: Procurement A&G	j	(5,298)	0.00000	0	0.00000	0
Brokerage Fee: Core Marketing	k	(6,389)	0.92025	(5,879)	0.92025	(5,879)
Brokerage Fee: Noncore Marketing	l	(123)	0.00000	0	0.00000	0
Long Term Contract Revenue	a	(2,858)	0.29897	(854)	0.30638	(876)
SUBTOTAL - Adjusted Base		1,088,676		721,201		726,138
Pipe Demand Charges	6	176,496	0.33861	59,764	0.33861	59,764
Pipeline Demand Trueup	16	2,401	0.00000	0	0.00000	0
Gas Storage Carrying Costs	7	14,574	0.42577	6,205	0.42577	6,205
Gas Storage Trueup	17	1,708	0.00000	0	0.00000	0
Take-or-Pay Transition Costs	1	27,500	0.29846	8,208	0.30638	8,425
Take-or-Pay Trueup	1	20,467	0.29846	6,109	0.30638	6,271
CFA Debt Service and Expense	2	2,628	0.43335	1,139	0.44961	1,182
Gas Exploration & Development Account	1	50,000	0.29846	14,923	0.30638	15,319
LUAF & CDU	11	61,841	0.29688	18,359	0.29794	18,425
CPUC Fee	12	4,489	0.39684	1,781	0.39874	1,790
LIRA A&G	14	1,961	0.41096	806	0.42702	837
RD&D Trueup - Core	19	728	0.74135	540	0.74135	540
RD&D Trueup - Noncore	17	352	0.00000	0	0.00000	0
Noncore Base Cost Adjustment	17	(193)	0.00000	0	0.00000	0
1990 ACAP F&U Adjustment	20	(1,021)	0.00000	0	0.00000	0
Corporate Franchise Tax Adjustment	21	(289)	0.00000	0	0.00000	0
Earthquake Recovery Adjustment	n	486	0.00000	0	0.00000	0
TOTAL - Forecasted Period Costs		1,452,804		839,035		844,896
AMORTIZATION OF BALANCING ACCOUNTS						
Gas Core Fixed Cost	3	49,873	0.70143	34,982	0.70143	34,982
Noncore Transition Cost	9	(2,699)	0.00000	0	0.00000	0
Enhanced Oil Recovery	5	(2,492)	0.62152	(1,549)	0.62152	(1,549)
A&S Interutility	6	(109)	0.33861	(37)	0.33861	(37)
CFA Debt Service and Expense	2	(1,327)	0.43335	(575)	0.44961	(597)
Core TOP	3	0	0.70143	0	0.70143	0
NGV	1	0	0.29846	0	0.30638	0
LIRA	14	(8,277)	0.41096	(3,402)	0.42702	(3,534)
COGEN Shortfall	13	1,106	0.00000	0	0.00000	0
TOTAL - Forecasted Acct Balances		36,075		29,420		29,266
F&U		13,793		8,041		8,094
TOTAL - Transport Revenue Requirement		1,502,672		876,496		882,255
ALLOCATION ADJUSTMENTS						
G-10 Allocated Employee Discount	18	969	0.66696	646	0.66696	646
GC-2 Shortfall		(7,941)		0		0
GC-2 Shortfall Allocated	8	7,941	0.30505	2,422	0.31332	2,488
LIRA Discount Benefits		(17,268)		(17,268)		(17,268)
LIRA Discount Expenses	14	17,268	0.41096	7,096	0.42702	7,374
TOTAL - Transport Costs		1,503,641		869,394		875,496

TABLE 5A

PACIFIC GAS AND ELECTRIC COMPANY
SMALL COMMERCIAL (SUMMER) CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1991 to March 31, 1992

	ALLOC INDEX	SYSTEM COST ($000)	UNADJ ALLOC FACTOR	UNADJ COST ($000)	ADJ ALLOC FACTOR	ADJ COST ($000)
FORECAST PERIOD COSTS						
Commodity Related Base	a	10,145	0.10572	1,072	0.10834	1,099
Transmission Base	e	212,600	0.11185	23,780	0.11452	24,348
Storage Base	c	43,869	0.12045	5,284	0.12324	5,406
Distribution Base	d	276,945	0.17041	47,195	0.17262	47,807
Customer Base	b	499,381	0.07613	38,018	0.07613	38,018
50% Adminstrative and General	m	88,634	0.10668	9,455	0.10935	9,692
Other Operating Revenue	f	(9,149)	0.11029	(1,009)	0.11168	(1,022)
SUBTOTAL - Base (Margin)		1,122,424		123,795		125,348
EOR Credit	h	(12,187)	0.11050	(1,347)	0.11206	(1,366)
Interutility Transportation Service	e	(6,893)	0.11185	(771)	0.11452	(789)
Brokerage Fee: Procurement A&G	j	(5,298)	0.00000	0	0.00000	0
Brokerage Fee: Core Marketing	k	(6,389)	0.07769	(496)	0.07769	(496)
Brokerage Fee: Noncore Marketing	l	(123)	0.00000	0	0.00000	0
Long Term Contract Revenue	a	(2,858)	0.10572	(302)	0.10834	(310)
SUBTOTAL - Adjusted Base		1,088,676		120,879		122,387
Pipe Demand Charges	6	176,496	0.00000	0	0.00000	0
Pipeline Demand Trueup	16	2,401	0.00000	0	0.00000	0
Gas Storage Carrying Costs	7	14,574	0.00000	0	0.00000	0
Gas Storage Trueup	17	1,708	0.00000	0	0.00000	0
Take-or-Pay Transition Costs	1	27,500	0.00000	0	0.00000	0
Take-or-Pay Trueup	1	20,467	0.00000	0	0.00000	0
CFA Debt Service and Expense	2	2,628	0.00000	0	0.00000	0
Gas Exploration & Development Account	1	50,000	0.00000	0	0.00000	0
LUAF & GDU	11	61,841	0.04974	3,076	0.04991	3,087
CPUC Fee	12	4,489	0.06540	294	0.06554	294
LIRA A&G	14	1,961	0.00000	0	0.00000	0
RD&D Trueup - Core	19	728	0.00000	0	0.00000	0
RD&D Trueup - Noncore	17	352	0.00000	0	0.00000	0
Noncore Base Cost Adjustment	17	(193)	0.00000	0	0.00000	0
1990 ACAP F&U Adjustment	20	(1,021)	0.00000	0	0.00000	0
Corporate Franchise Tax Adjustment	21	(289)	0.00000	0	0.00000	0
Earthquake Recovery Adjustment	n	486	0.00000	0	0.00000	0
TOTAL - Forecasted Period Costs		1,452,804		124,249		125,768
AMORTIZATION OF BALANCING ACCOUNTS						
Gas Core Fixed Cost	3	49,873	0.00000	0	0.00000	0
Noncore Transition Cost	9	(2,699)	0.00000	0	0.00000	0
Enhanced Oil Recovery	5	(2,492)	0.11270	(281)	0.11270	(281)
A&S Interutility	6	(109)	0.00000	0	0.00000	0
CFA Debt Service and Expense	2	(1,327)	0.00000	0	0.00000	0
Core TOP	3	0	0.00000	0	0.00000	0
NGV	1	0	0.00000	0	0.00000	0
LIRA	14	(8,277)	0.00000	0	0.00000	0
COGEN Shortfall	13	1,106	0.00000	0	0.00000	0
TOTAL - Forecasted Acct Balances		36,075		(281)		(281)
F&U		13,793		1,155		1,169
TOTAL - Transport Revenue Requirement		1,502,672		125,123		126,656
ALLOCATION ADJUSTMENTS						
G-10 Allocated Employee Discount	18	969	0.11241	109	0.11241	109
GC-2 Shortfall		(7,941)		0		0
GC-2 Shortfall Allocated	8	7,941	0.00000	0	0.00000	0
LIRA Discount Benefits		(17,268)		0		0
LIRA Discount Expenses	14	17,268	0.00000	0	0.00000	0
TOTAL - Transport Costs		1,503,641		125,232		126,765

TABLE 5B

PACIFIC GAS AND ELECTRIC COMPANY
SMALL COMMERCIAL (WINTER) CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1991 to March 31, 1992

	ALLOC INDEX	SYSTEM COST ($000)	ALLOC	UNADJ COST ($000)	ADJ ALLOC FACTOR	ADJ COST ($000)
RECAST PERIOD COSTS						
Commodity Related Base	a	10,145	0.00000	0	0.00000	0
Transmission Base	e	212,600	0.00000	0	0.00000	0
Storage Base	c	43,869	0.00000	0	0.00000	0
Distribution Base	d	276,945	0.00000	0	0.00000	0
Customer Base	b	499,381	0.00000	0	0.00000	0
50% Adminstrative and General	m	88,634	0.00000	0	0.00000	0
Other Operating Revenue	f	(9,149)	0.00000	0	0.00000	0
SUBTOTAL - Base (Margin)		1,122,424		0		0
EOR Credit	h	(12,187)	0.00000	0	0.00000	0
Interutility Transportation Service	e	(6,893)	0.00000	0	0.00000	0
Brokerage Fee: Procurement A&G	j	(5,298)	0.00000	0	0.00000	0
Brokerage Fee: Core Marketing	k	(6,389)	0.00000	0	0.00000	0
Brokerage Fee: Noncore Marketing	l	(123)	0.00000	0	0.00000	0
Long Term Contract Revenue	a	(2,858)	0.00000	0	0.00000	0
SUBTOTAL - Adjusted Base		1,088,676		0		0
Pipe Demand Charges	6	176,496	0.11452	20,213	0.11452	20,213
Pipeline Demand Trueup	16	2,401	0.00000	0	0.00000	0
Gas Storage Carrying Costs	7	14,574	0.12324	1,796	0.12324	1,796
Gas Storage Trueup	17	1,708	0.00000	0	0.00000	0
Take-or-Pay Transition Costs	1	27,500	0.10554	2,902	0.10834	2,979
Take-or-Pay Trueup	1	20,467	0.10554	2,160	0.10834	2,217
CFA Debt Service and Expense	2	2,628	0.15324	403	0.15899	418
Gas Exploration & Development Account	1	50,000	0.10554	5,277	0.10834	5,417
LUAF & CDU	11	61,841	0.05504	3,404	0.05524	3,416
CPUC Fee	12	4,489	0.07238	325	0.07254	326
LIRA A&G	14	1,961	0.15929	312	0.16552	325
RD&D Trueup - Core	19	728	0.21458	156	0.21458	156
RD&D Trueup - Noncore	17	352	0.00000	0	0.00000	0
Noncore Base Cost Adjustment	17	(193)	0.00000	0	0.00000	0
1990 ACAP F&U Adjustment	20	(1,021)	0.00000	0	0.00000	0
Corporate Franchise Tax Adjustment	21	(289)	0.00000	0	0.00000	0
Earthquake Recovery Adjustment	n	486	0.00000	0	0.00000	0
TOTAL - Forecasted Period Costs		1,452,804		36,949		37,263
ORTIZATION OF BALANCING ACCOUNTS						
Gas Core Fixed Cost	3	49,873	0.24804	12,371	0.24804	12,371
Noncore Transition Cost	9	(2,699)	0.00000	0	0.00000	0
Enhanced Oil Recovery	5	(2,492)	0.00000	0	0.00000	0
A&S Interutility	6	(109)	0.11452	(12)	0.11452	(12)
CFA Debt Service and Expense	2	(1,327)	0.15324	(203)	0.15899	(211)
Core TOP	3	0	0.24804	0	0.24804	0
NGV	1	0	0.10554	0	0.10834	0
LIRA	14	(8,277)	0.15929	(1,318)	0.16552	(1,370)
COGEN Shortfall	13	1,106	0.00000	0	0.00000	0
TOTAL - Forecasted Acct Balances		36,075		10,836		10,777
F&U		13,793		599		432
TOTAL - Transport Revenue Requirement		1,502,672		48,385		48,472
LOCATION ADJUSTMENTS						
G-10 Allocated Employee Discount	18	969	0.00000	0	0.00000	0
GC-2 Shortfall		(7,941)		0		0
GC-2 Shortfall Allocated	8	7,941	0.10787	857	0.11080	880
LIRA Discount Benefits		(17,268)		0		0
LIRA Discount Expenses	14	17,268	0.15929	2,751	0.16552	2,858
TOTAL - Transport Costs		1,503,641		51,992		52,210

TABLE 6A

PACIFIC GAS AND ELECTRIC COMPANY
NATURAL GAS VEHICLE (SUMMER) CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1991 to March 31, 1992

	ALLOC INDEX	SYSTEM COST ($000)	UNADJ ALLOC FACTOR	UNADJ COST ($000)	ADJ ALLOC FACTOR	ADJ COST ($000)
FORECAST PERIOD COSTS						
Commodity Related Base	a	10,145	0.00000	0	0.00000	0
Transmission Base	e	212,600	0.00000	0	0.00000	0
Storage Base	c	43,869	0.00000	0	0.00000	0
Distribution Base	d	276,945	0.00000	0	0.00000	0
Customer Base	b	499,381	0.00000	0	0.00000	0
50% Administrative and General	m	88,634	0.00000	0	0.00000	0
Other Operating Revenue	f	(9,149)	0.00000	0	0.00000	0
SUBTOTAL - Base (Margin)		1,122,424		0		0
EOR Credit	h	(12,187)	0.00000	0	0.00000	0
Interutility Transportation Service	e	(6,893)	0.00000	0	0.00000	0
Brokerage Fee: Procurement A&G	j	(5,298)	0.00000	0	0.00000	0
Brokerage Fee: Core Marketing	k	(6,389)	0.00000	0	0.00000	0
Brokerage Fee: Noncore Marketing	l	(123)	0.00000	0	0.00000	0
Long Term Contract Revenue	a	(2,858)	0.00000	0	0.00000	0
SUBTOTAL - Adjusted Base		1,088,676		0		0
Pipe Demand Charges	6	176,496	0.00000	0	0.00000	0
Pipeline Demand Trueup	16	2,401	0.00000	0	0.00000	0
Gas Storage Carrying Costs	7	14,574	0.00000	0	0.00000	0
Gas Storage Trueup	17	1,708	0.00000	0	0.00000	0
Take-or-Pay Transition Costs	1	27,500	0.00000	0	0.00000	0
Take-or-Pay Trueup	1	20,467	0.00000	0	0.00000	0
CFA Debt Service and Expense	2	2,628	0.00000	0	0.00000	0
Gas Exploration & Development Account	1	50,000	0.00000	0	0.00000	0
LUAF & CDU	11	61,841	0.00000	0	0.00000	0
CPUC Fee	12	4,489	0.00000	0	0.00000	0
LIRA A&G	14	1,961	0.00000	0	0.00000	0
RD&D Trueup - Core	19	728	0.00000	0	0.00000	0
RD&D Trueup - Noncore	17	352	0.00000	0	0.00000	0
Noncore Base Cost Adjustment	17	(193)	0.00000	0	0.00000	0
1990 ACAP F&U Adjustment	20	(1,021)	0.00000	0	0.00000	0
Corporate Franchise Tax Adjustment	21	(289)	0.00000	0	0.00000	0
Earthquake Recovery Adjustment	n	486	0.00000	0	0.00000	0
TOTAL - Forecasted Period Costs		1,452,804		0		0
AMORTIZATION OF BALANCING ACCOUNTS						
Gas Core Fixed Cost	3	49,873	0.00000	0	0.00000	0
Noncore Transition Cost	9	(2,699)	0.00000	0	0.00000	0
Enhanced Oil Recovery	5	(2,492)	0.00000	0	0.00000	0
A&S Interutility	6	(109)	0.00000	0	0.00000	0
CFA Debt Service and Expense	2	(1,327)	0.00000	0	0.00000	0
Core TOP	3	0	0.00000	0	0.00000	0
NGV	1	0	0.00000	0	0.00000	0
LIRA	14	(8,277)	0.00000	0	0.00000	0
COGEN Shortfall	13	1,106	0.00000	0	0.00000	0
TOTAL - Forecasted Acct Balances		36,075		0		0
F&U		13,793		0		0
TOTAL - Transport Revenue Requirement		1,502,672		0		0
ALLOCATION ADJUSTMENTS						
G-10 Allocated Employee Discount	18	969	0.00000	0	0.00000	0
GC-2 Shortfall		(7,941)		0		0
GC-2 Shortfall Allocated	8	7,941	0.00000	0	0.00000	0
LIRA Discount Benefits		(17,268)		0		0
LIRA Discount Expenses	14	17,268	0.00000	0	0.00000	0
TOTAL - Transport Costs		1,503,641		0		0

TABLE 6B

PACIFIC GAS AND ELECTRIC COMPANY
NATURAL GAS VEHICLE (WINTER) CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1991 to March 31, 1992

	ALLOC INDEX	SYSTEM COST ($000)	UNADJ ALLOC FACTOR	UNADJ COST ($000)	ADJ ALLOC FACTOR	ADJ COST ($000)
FORECAST PERIOD COSTS						
Commodity Related Base	a	10,145	0.00000	0	0.00000	0
Transmission Base	e	212,600	0.00000	0	0.00000	0
Storage Base	c	43,869	0.00000	0	0.00000	0
Distribution Base	d	276,945	0.00000	0	0.00000	0
Customer Base	b	499,381	0.00000	0	0.00000	0
50% Administrative and General	m	88,634	0.00000	0	0.00000	0
Other Operating Revenue	f	(9,149)	0.00000	0	0.00000	0
SUBTOTAL - Base (Margin)		1,122,424		0		0
EOR Credit	h	(12,187)	0.00000	0	0.00000	0
Interutility Transportation Service	e	(6,893)	0.00000	0	0.00000	0
Brokerage Fee: Procurement A&G	j	(5,298)	0.00000	0	0.00000	0
Brokerage Fee: Core Marketing	k	(6,389)	0.00000	0	0.00000	0
Brokerage Fee: Noncore Marketing	l	(123)	0.00000	0	0.00000	0
Long Term Contract Revenue	a	(2,858)	0.00000	0	0.00000	0
SUBTOTAL - Adjusted Base		1,088,676		0		0
Pipe Demand Charges	6	176,496	0.00000	0	0.00000	0
Pipeline Demand Trueup	16	2,401	0.00000	0	0.00000	0
Gas Storage Carrying Costs	7	14,574	0.00000	0	0.00000	0
Gas Storage Trueup	17	1,708	0.00000	0	0.00000	0
Take-or-Pay Transition Costs	1	27,500	0.00000	0	0.00000	0
Take-or-Pay Trueup	1	20,467	0.00000	0	0.00000	0
CFA Debt Service and Expense	2	2,628	0.00000	0	0.00000	0
Gas Exploration & Development Account	1	50,000	0.00000	0	0.00000	0
LUAF & CDU	11	61,841	0.00000	0	0.00000	0
CPUC Fee	12	4,489	0.00000	0	0.00000	0
LIRA A&G	14	1,961	0.00000	0	0.00000	0
RD&D Trueup - Core	19	728	0.00000	0	0.00000	0
RD&D Trueup - Noncore	17	352	0.00000	0	0.00000	0
Noncore Base Cost Adjustment	17	(193)	0.00000	0	0.00000	0
1990 ACAP F&U Adjustment	20	(1,021)	0.00000	0	0.00000	0
Corporate Franchise Tax Adjustment	21	(289)	0.00000	0	0.00000	0
Earthquake Recovery Adjustment	n	486	0.00000	0	0.00000	0
TOTAL - Forecasted Period Costs		1,452,804		0		0
AMORTIZATION OF BALANCING ACCOUNTS						
Gas Core Fixed Cost	3	49,873	0.00000	0	0.00000	0
Noncore Transition Cost	9	(2,699)	0.00000	0	0.00000	0
Enhanced Oil Recovery	5	(2,492)	0.00000	0	0.00000	0
A&S Interutility	6	(109)	0.00000	0	0.00000	0
CFA Debt Service and Expense	2	(1,327)	0.00000	0	0.00000	0
Core TOP	3	0	0.00000	0	0.00000	0
NGV	1	0	0.00000	0	0.00000	0
LIRA	14	(8,277)	0.00000	0	0.00000	0
COGEN Shortfall	13	1,106	0.00000	0	0.00000	0
TOTAL - Forecasted Acct Balances		36,075		0		0
F&U		13,793		0		0
TOTAL - Transport Revenue Requirement		1,502,672		0		0
ALLOCATION ADJUSTMENTS						
G-10 Allocated Employee Discount	18	969	0.00000	0	0.00000	0
GC-2 Shortfall		(7,941)		0		0
GC-2 Shortfall Allocated	8	7,941	0.00000	0	0.00000	0
LIRA Discount Benefits		(17,268)		0		0
LIRA Discount Expenses	14	17,268	0.00000	0	0.00000	0
TOTAL - Transport Costs		1,503,641		0		0

TABLE 7A

PACIFIC GAS AND ELECTRIC COMPANY
LARGE COMMERCIAL (SUMMER) CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1991 to March 31, 1992

	ALLOC INDEX	SYSTEM COST ($000)	UNADJ ALLOC FACTOR	UNADJ COST ($000)	ADJ ALLOC FACTOR	ADJ COST ($000)
FORECAST PERIOD COSTS						
Commodity Related Base	a	10,145	0.02154	218	0.02207	224
Transmission Base	e	212,600	0.02284	4,855	0.02338	4,971
Storage Base	c	43,869	0.02473	1,085	0.02531	1,110
Distribution Base	d	276,945	0.03505	9,708	0.03551	9,834
Customer Base	b	499,381	0.00202	1,008	0.00202	1,008
50% Adminstrative and General	m	88,634	0.02173	1,926	0.02228	1,974
Other Operating Revenue	f	(9,149)	0.01662	(152)	0.01690	(155)
SUBTOTAL - Base (Margin)		1,122,424		18,649		18,967
EOR Credit	h	(12,187)	0.01745	(213)	0.01777	(217)
Interutility Transportation Service	e	(6,893)	0.02284	(157)	0.02338	(161)
Brokerage Fee: Procurement A&G	j	(5,298)	0.00000	0	0.00000	0
Brokerage Fee: Core Marketing	k	(6,389)	0.00206	(13)	0.00206	(13)
Brokerage Fee: Noncore Marketing	l	(123)	0.00000	0	0.00000	0
Long Term Contract Revenue	a	(2,858)	0.02154	(62)	0.02207	(63)
SUBTOTAL - Adjusted Base		1,088,676		18,204		18,513
Pipe Demand Charges	6	176,496	0.00000	0	0.00000	0
Pipeline Demand Trueup	16	2,401	0.00000	0	0.00000	0
Gas Storage Carrying Costs	7	14,574	0.00000	0	0.00000	0
Gas Storage Trueup	17	1,708	0.00000	0	0.00000	0
Take-or-Pay Transition Costs	1	27,500	0.00000	0	0.00000	0
Take-or-Pay Trueup	1	20,467	0.00000	0	0.00000	0
CFA Debt Service and Expense	2	2,628	0.00000	0	0.00000	0
Gas Exploration & Development Account	1	50,000	0.00000	0	0.00000	0
LUAF & CDU	11	61,841	0.01006	622	0.01010	624
CPUC Fee	12	4,489	0.01205	54	0.01333	60
LIRA A&G	14	1,961	0.00000	0	0.00000	0
RD&D Trueup - Core	19	728	0.00000	0	0.00000	0
RD&D Trueup - Noncore	17	352	0.00000	0	0.00000	0
Noncore Base Cost Adjustment	17	(193)	0.00000	0	0.00000	0
1990 ACAP F&U Adjustment	20	(1,021)	0.00000	0	0.00000	0
Corporate Franchise Tax Adjustment	21	(289)	0.00000	0	0.00000	0
Earthquake Recovery Adjustment	n	486	0.00000	0	0.00000	0
TOTAL - Forecasted Period Costs		1,452,804		18,880		19,197
AMORTIZATION OF BALANCING ACCOUNTS						
Gas Core Fixed Cost	3	49,873	0.00000	0	0.00000	0
Noncore Transition Cost	9	(2,699)	0.00000	0	0.00000	0
Enhanced Oil Recovery	5	(2,492)	0.01789	(45)	0.01789	(45)
A&S Interutility	6	(109)	0.00000	0	0.00000	0
CFA Debt Service and Expense	2	(1,327)	0.00000	0	0.00000	0
Core TOP	3	0	0.00000	0	0.00000	0
NGV	1	0	0.00000	0	0.00000	0
LIRA	14	(8,277)	0.00000	0	0.00000	0
COGEN Shortfall	13	1,106	0.00000	0	0.00000	0
TOTAL - Forecasted Acct Balances		36,075		(45)		(45)
F&U		13,793		175		178
TOTAL - Transport Revenue Requirement		1,502,672		19,011		19,331
ALLOCATION ADJUSTMENTS						
G-10 Allocated Employee Discount	18	969	0.01700	16	0.01700	16
GC-2 Shortfall		(7,941)		0		0
GC-2 Shortfall Allocated	8	7,941	0.00000	0	0.00000	0
LIRA Discount Benefits		(17,268)		0		0
LIRA Discount Expenses	14	17,268	0.00000	0	0.00000	0
TOTAL - Transport Costs		1,503,641		19,028		19,347

TABLE 7B

PACIFIC GAS AND ELECTRIC COMPANY
LARGE COMMERCIAL (WINTER) CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1991 to March 31, 1992

	ALLOC INDEX	SYSTEM COST ($000)	UNADJ ALLOC FACTOR	UNADJ COST ($000)	ADJ ALLOC FACTOR	ADJ COST ($000)
FORECAST PERIOD COSTS						
Commodity Related Base	a	10,145	0.00000	0	0.00000	0
Transmission Base	e	212,600	0.00000	0	0.00000	0
Storage Base	c	43,869	0.00000	0	0.00000	0
Distribution Base	d	276,945	0.00000	0	0.00000	0
Customer Base	b	499,381	0.00000	0	0.00000	0
50% Adminstrative and General	m	88,634	0.00000	0	0.00000	0
Other Operating Revenue	f	(9,149)	0.00000	0	0.00000	0
SUBTOTAL - Base (Margin)		1,122,424		0		0
EOR Credit	h	(12,187)	0.00000	0	0.00000	0
Interutility Transportation Service	e	(6,893)	0.00000	0	0.00000	0
Brokerage Fee: Procurement A&G	j	(5,298)	0.00000	0	0.00000	0
Brokerage Fee: Core Marketing	k	(6,389)	0.00000	0	0.00000	0
Brokerage Fee: Noncore Marketing	l	(123)	0.00000	0	0.00000	0
Long Term Contract Revenue	a	(2,858)	0.00000	0	0.00000	0
SUBTOTAL - Adjusted Base		1,088,676		0		0
Pipe Demand Charges	6	176,496	0.02338	4,127	0.02338	4,127
Pipeline Demand Trueup	16	2,401	0.00000	0	0.00000	0
Gas Storage Carrying Costs	7	14,574	0.02531	369	0.02531	369
Gas Storage Trueup	17	1,708	0.00000	0	0.00000	0
Take-or-Pay Transition Costs	1	27,500	0.02150	591	0.02207	607
Take-or-Pay Trueup	1	20,467	0.02150	440	0.02207	452
CFA Debt Service and Expense	2	2,628	0.03122	82	0.03239	85
Gas Exploration & Development Account	1	50,000	0.02150	1,075	0.02207	1,104
LUAF & CDU	11	61,841	0.01128	698	0.01132	700
CPUC Fee	12	4,489	0.01352	61	0.01495	67
LIRA A&G	14	1,961	0.03245	64	0.03372	66
RD&D Trueup - Core	19	728	0.04406	32	0.04406	32
RD&D Trueup - Noncore	17	352	0.00000	0	0.00000	0
Noncore Base Cost Adjustment	17	(193)	0.00000	0	0.00000	0
1990 ACAP F&U Adjustment	20	(1,021)	0.00000	0	0.00000	0
Corporate Franchise Tax Adjustment	21	(289)	0.00000	0	0.00000	0
Earthquake Recovery Adjustment	n	486	0.00000	0	0.00000	0
TOTAL - Forecasted Period Costs		1,452,804		7,538		7,609
AMORTIZATION OF BALANCING ACCOUNTS						
Gas Core Fixed Cost	3	49,873	0.05053	2,520	0.05053	2,520
Noncore Transition Cost	9	(2,699)	0.00000	0	0.00000	0
Enhanced Oil Recovery	5	(2,492)	0.00000	0	0.00000	0
A&S Interutility	6	(109)	0.02338	(3)	0.02338	(3)
CFA Debt Service and Expense	2	(1,327)	0.03122	(41)	0.03239	(43)
Core TOP	3	0	0.05053	0	0.05053	0
NGV	1	0	0.02150	0	0.02207	0
LIRA	14	(8,277)	0.03245	(269)	0.03372	(279)
COGEN Shortfall	13	1,106	0.00000	0	0.00000	0
TOTAL - Forecasted Acct Balances		36,075		2,208		2,195
F&U		13,793		88		88
TOTAL - Transport Revenue Requirement		1,502,672		9,833		9,892
ALLOCATION ADJUSTMENTS						
G-10 Allocated Employee Discount	18	969	0.00000	0	0.00000	0
GC-2 Shortfall		(7,941)		0		0
GC-2 Shortfall Allocated	8	7,941	0.02198	175	0.02257	179
LIRA Discount Benefits		(17,268)		0		0
LIRA Discount Expenses	14	17,268	0.03245	560	0.03372	582
TOTAL - Transport Costs		1,503,641		10,568		10,654

TABLE 8

PACIFIC GAS AND ELECTRIC COMPANY
P2B CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1991 to March 31, 1992

	ALLOC INDEX	SYSTEM COST ($000)	UNADJ ALLOC FACTOR	UNADJ COST ($000)	ADJ ALLOC FACTOR	ADJ COST ($000)
FORECAST PERIOD COSTS						
Commodity Related Base	a	10,145	0.02415	245	0.02401	244
Transmission Base	e	212,600	0.02331	4,955	0.02315	4,922
Storage Base	c	43,869	0.02023	887	0.02007	881
Distribution Base	d	276,945	0.01679	4,651	0.01650	4,570
Customer Base	b	499,381	0.00125	625	0.00125	625
50% Administrative and General	m	88,634	0.02437	2,160	0.02423	2,148
Other Operating Revenue	f	(9,149)	0.01195	(109)	0.01183	(108)
SUBTOTAL - Base (Margin)		1,122,424		13,414		13,280
EOR Credit	h	(12,187)	0.01348	(164)	0.01336	(163)
Interutility Transportation Service	e	(6,893)	0.02331	(161)	0.02315	(160)
Brokerage Fee: Procurement A&G	j	(5,298)	0.04209	(223)	0.04263	(226)
Brokerage Fee: Core Marketing	k	(6,389)	0.00000	0	0.00000	0
Brokerage Fee: Noncore Marketing	l	(723)	0.06236	(8)	0.06236	(8)
Long Term Contract Revenue	a	(2,858)	0.02415	(69)	0.02401	(69)
SUBTOTAL - Adjusted Base		1,088,676		12,790		12,655
Pipe Demand Charges	6	176,496	0.02315	4,086	0.02315	4,086
Pipeline Demand Trueup	16	2,401	0.04422	106	0.04422	106
Gas Storage Carrying Costs	7	14,574	0.02007	293	0.02007	293
Gas Storage Trueup	17	1,708	0.04716	81	0.04716	81
Take-or-Pay Transition Costs	1	27,500	0.02411	663	0.02401	660
Take-or-Pay Trueup	1	20,467	0.02411	493	0.02401	491
CFA Debt Service and Expense	2	2,628	0.03501	92	0.03523	93
Gas Exploration & Development Account	1	50,000	0.02411	1,206	0.02401	1,200
LUAF & GDU	11	61,841	0.00000	0	0.02402	1,486
CPUC Fee	12	4,489	0.00000	0	0.03215	144
LIRA A&G	14	1,961	0.03639	71	0.03668	72
RD&D Trueup - Core	19	728	0.00000	0	0.00000	0
RD&D Trueup - Noncore	17	352	0.04716	17	0.04716	17
Noncore Base Cost Adjustment	17	(193)	0.04716	(9)	0.04716	(9)
1990 ACAP F&U Adjustment	20	(1,021)	0.05222	(53)	0.05222	(53)
Corporate Franchise Tax Adjustment	21	(289)	0.05710	(17)	0.05710	(17)
Earthquake Recovery Adjustment	n	486	0.10332	50	0.10878	53
TOTAL - Forecasted Period Costs		1,452,804		19,868		21,357
AMORTIZATION OF BALANCING ACCOUNTS						
Gas Core Fixed Cost	3	49,873	0.00000	0	0.00000	0
Noncore Transition Cost	9	(2,699)	0.04197	(113)	0.04263	(115)
Enhanced Oil Recovery	5	(2,492)	0.01322	(33)	0.01322	(33)
A&S Interutility	6	(109)	0.02315	(3)	0.02315	(3)
CFA Debt Service and Expense	2	(1,327)	0.03501	(46)	0.03523	(47)
Core TOP	3	0	0.00000	0	0.00000	0
NGV	1	0	0.02411	0	0.02401	0
LIRA	14	(8,277)	0.03639	(301)	0.03668	(304)
COGEN Shortfall	13	1,106	0.00000	0	0.00000	0
TOTAL - Forecasted Acct Balances		36,075		(496)		(501)
F&U		13,793		181		195
TOTAL - Transport Revenue Requirement		1,502,672		19,553		21,051
ALLOCATION ADJUSTMENTS						
G-10 Allocated Employee Discount	18	969	0.01163	11	0.01163	11
GC-2 Shortfall		(7,941)		0		0
GC-2 Shortfall Allocated	8	7,941	0.02464	196	0.02455	195
LIRA Discount Benefits		(17,268)		0		0
LIRA Discount Expenses	14	17,268	0.03639	628	0.03668	633
TOTAL - Transport Costs		1,503,641		20,388		21,891

TABLE 9

PACIFIC GAS AND ELECTRIC COMPANY
IND CUSTOMERS (INCLUDING GC-2) COST ALLOCATION

Forecast Period: April 1, 1991 to March 31, 1992

	ALLOC INDEX	SYSTEM COST ($000)	UNADJ ALLOC FACTOR	UNADJ COST ($000)	ADJ ALLOC FACTOR	ADJ COST ($000)
FORECAST PERIOD COSTS						
Commodity Related Base	a	10,145	0.23793	2,414	0.22063	2,238
Transmission Base	e	212,600	0.22983	48,861	0.21295	45,273
Storage Base	c	43,869	0.21497	9,431	0.19809	8,690
Distribution Base	d	276,945	0.12111	33,541	0.11045	30,587
Customer Base	b	499,381	0.01290	6,443	0.01290	6,443
50% Adminstrative and General	m	88,634	0.24008	21,279	0.22268	19,737
Other Operating Revenue	f	(9,149)	0.10779	(986)	0.09983	(913)
SUBTOTAL - Base (Margin)		1,122,424		120,983		112,056
EOR Credit	h	(12,187)	0.12424	(1,514)	0.11509	(1,403)
Interutility Transportation Service	e	(6,893)	0.22983	(1,584)	0.21295	(1,468)
Brokerage Fee: Procurement A&G	j	(5,298)	0.41468	(2,197)	0.39173	(2,075)
Brokerage Fee: Core Marketing	k	(6,389)	0.00000	0	0.00000	0
Brokerage Fee: Noncore Marketing	l	(123)	0.64325	(79)	0.64325	(79)
Long Term Contract Revenue	a	(2,858)	0.23793	(680)	0.22063	(631)
SUBTOTAL - Adjusted Base		1,088,676		114,929		106,400
Pipe Demand Charges	6	176,496	0.21295	37,585	0.21295	37,585
Pipeline Demand Trueup	16	2,401	0.40680	977	0.40680	977
Gas Storage Carrying Costs	7	14,574	0.19809	2,887	0.19809	2,887
Gas Storage Trueup	17	1,708	0.46536	795	0.46536	795
Take-or-Pay Transition Costs	1	27,500	0.23912	6,576	0.22063	6,067
Take-or-Pay Trueup	1	20,467	0.23912	4,894	0.22063	4,516
CFA Debt Service and Expense	2	2,628	0.34719	912	0.32377	851
Gas Exploration & Development Account	1	50,000	0.23912	11,956	0.22063	11,031
LUAF & GDU	11	61,841	0.26235	16,224	0.23665	14,635
CPUC Fee	12	4,489	0.30926	1,388	0.27509	1,235
LIRA A&G	14	1,961	0.36090	708	0.33706	661
RD&D Trueup - Core	19	728	0.00000	0	0.00000	0
RD&D Trueup - Noncore	17	352	0.46536	164	0.46536	164
Noncore Base Cost Adjustment	17	(193)	0.46536	(90)	0.46536	(90)
1990 ACAP F&U Adjustment	20	(1,021)	0.44510	(454)	0.44510	(454)
Corporate Franchise Tax Adjustment	21	(289)	0.48004	(139)	0.48004	(139)
Earthquake Recovery Adjustment	n	486	0.74511	362	0.72809	354
TOTAL - Forecasted Period Costs		1,452,804		199,674		187,474
AMORTIZATION OF BALANCING ACCOUNTS						
Gas Core Fixed Cost	3	49,873	0.00000	0	0.00000	0
Noncore Transition Cost	9	(2,699)	0.41624	(1,123)	0.39173	(1,057)
Enhanced Oil Recovery	5	(2,492)	0.11369	(283)	0.11369	(283)
A&S Interutility	6	(109)	0.21295	(23)	0.21295	(23)
CFA Debt Service and Expense	2	(1,327)	0.34719	(461)	0.32377	(430)
Core TOP	3	0	0.00000	0	0.00000	0
NGV	1	0	0.23912	0	0.22063	0
LIRA	14	(8,277)	0.36090	(2,987)	0.33706	(2,790)
COGEN Shortfall	13	1,106	0.00000	0	0.00000	0
TOTAL - Forecasted Acct Balances		36,075		(4,878)		(4,583)
F&U		13,793		1,820		1,708
TOTAL - Transport Revenue Requirement		1,502,672		196,616		184,599
ALLOCATION ADJUSTMENTS						
G-10 Allocated Employee Discount	18	969	0.09775	95	0.09775	95
GC-2 Shortfall		(7,941)		(5,628)		(5,628)
GC-2 Shortfall Allocated	8	7,941	0.23157	1,839	0.21245	1,687
LIRA Discount Benefits		(17,268)		0		0
LIRA Discount Expenses	14	17,268	0.36090	6,232	0.33706	5,820
TOTAL - Transport Costs		1,503,641		199,153		186,573

TABLE 10

PACIFIC GAS AND ELECTRIC COMPANY
UEG CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1991 to March 31, 1992

	ALLOC INDEX	SYSTEM COST ($000)	UNADJ ALLOC FACTOR	UNADJ COST ($000)	ADJ ALLOC FACTOR	ADJ COST ($000)
FORECAST PERIOD COSTS						
Commodity Related Base	a	10,145	0.20167	2,046	0.20667	2,097
Transmission Base	e	212,600	0.17418	37,032	0.17835	37,917
Storage Base	c	43,869	0.10847	4,759	0.11099	4,869
Distribution Base	d	276,945	0.00000	0	0.00000	0
Customer Base	b	499,381	0.00247	1,233	0.00247	1,233
50% Adminstrative and General	m	88,634	0.20349	18,036	0.20858	18,488
Other Operating Revenue	f	(9,149)	0.05577	(510)	0.05709	(522)
SUBTOTAL - Base (Margin)		1,122,424		62,595		64,080
EOR Credit	h	(12,187)	0.07173	(874)	0.07344	(895)
Interutility Transportation Service	e	(6,893)	0.17418	(1,201)	0.17835	(1,229)
Brokerage Fee: Procurement A&G	j	(5,298)	0.35148	(1,862)	0.36694	(1,944)
Brokerage Fee: Core Marketing	k	(6,389)	0.00000	0	0.00000	0
Brokerage Fee: Noncore Marketing	l	(123)	0.12309	(15)	0.12309	(15)
Long Term Contract Revenue	a	(2,858)	0.20167	(576)	0.20667	(591)
SUBTOTAL - Adjusted Base		1,088,676		58,067		59,406
Pipe Demand Charges	6	176,496	0.17835	31,478	0.17835	31,478
Pipeline Demand Trueup	16	2,401	0.34070	818	0.34070	818
Gas Storage Carrying Costs	7	14,574	0.11099	1,618	0.11099	1,618
Gas Storage Trueup	17	1,708	0.26073	445	0.26073	445
Take-or-Pay Transition Costs	1	27,500	0.20133	5,537	0.20667	5,683
Take-or-Pay Trueup	1	20,467	0.20133	4,121	0.20667	4,230
CFA Debt Service and Expense	2	2,628	0.00000	0	0.00000	0
Gas Exploration & Development Account	1	50,000	0.20133	10,066	0.20667	10,333
LUAF & CDU	11	61,841	0.19987	12,360	0.20059	12,404
CPUC Fee	12	4,489	0.00000	0	0.00000	0
LIRA A&G	14	1,961	0.00000	0	0.00000	0
RD&D Trueup - Core	19	728	0.00000	0	0.00000	0
RD&D Trueup - Noncore	17	352	0.26073	92	0.26073	92
Noncore Base Cost Adjustment	17	(193)	0.26073	(50)	0.26073	(50)
1990 ACAP F&U Adjustment	20	(1,021)	0.30669	(313)	0.30669	(313)
Corporate Franchise Tax Adjustment	21	(289)	0.26810	(77)	0.26810	(77)
Earthquake Recovery Adjustment	n	486	0.00000	0	0.00000	0
TOTAL - Forecasted Period Costs		1,452,804		124,160		126,066
AMORTIZATION OF BALANCING ACCOUNTS						
Gas Core Fixed Cost	3	49,873	0.00000	0	0.00000	0
Noncore Transition Cost	9	(2,699)	0.35045	(946)	0.36694	(990)
Enhanced Oil Recovery	5	(2,492)	0.07172	(179)	0.07172	(179)
A&S Interutility	6	(109)	0.17835	(19)	0.17835	(19)
CFA Debt Service and Expense	2	(1,327)	0.00000	0	0.00000	0
Core TOP	3	0	0.00000	0	0.00000	0
NGV	1	0	0.20133	0	0.20667	0
LIRA	14	(8,277)	0.00000	0	0.00000	0
COGEN Shortfall	13	1,106	0.68867	762	0.69082	764
TOTAL - Forecasted Acct Balances		36,075		(382)		(424)
F&U		13,793		1,161		1,179
TOTAL - Transport Revenue Requirement		1,502,672		124,938		126,821
ALLOCATION ADJUSTMENTS						
G-10 Allocated Employee Discount	18	969	0.05459	53	0.05459	53
GC-2 Shortfall		(7,941)		(2,313)		(2,313)
GC-2 Shortfall Allocated	8	7,941	0.20577	1,634	0.21135	1,678
LIRA Discount Benefits		(17,268)		0		0
LIRA Discount Expenses	14	17,268	0.00000	0	0.00000	0
TOTAL - Transport Costs		1,503,641		124,313		126,239

TABLE 11

PACIFIC GAS AND ELECTRIC COMPANY
COGEN CUSTOMERS (INCLUDING GC-2) COST ALLOCATION

Forecast Period: April 1, 1991 to March 31, 1992

	ALLOC INDEX	SYSTEM. COST ($000)	UNADJ ALLOC FACTOR	UNADJ COST ($000)	ADJ ALLOC FACTOR	ADJ COST ($000)
FORECAST PERIOD COSTS						
Commodity Related Base	a	10,145	0.09108	924	0.09250	938
Transmission Base	e	212,600	0.08790	18,688	0.08919	18,962
Storage Base	c	43,869	0.07160	3,141	0.07256	3,183
Distribution Base	d	276,945	0.02464	6,823	0.02474	6,853
Customer Base	b	499,381	0.00301	1,502	0.00301	1,502
50% Administrative and General	m	88,634	0.09190	8,146	0.09335	8,274
Other Operating Revenue	f	(9,149)	0.03466	(317)	0.03510	(321)
SUBTOTAL - Base (Margin)		1,122,424		38,906		39,392
EOR Credit	h	(12,187)	0.04184	(510)	0.04239	(517)
Interutility Transportation Service	e	(6,893)	0.08790	(606)	0.08919	(615)
Brokerage Fee: Procurement A&G	j	(5,298)	0.15874	(841)	0.16423	(870)
Brokerage Fee: Core Marketing	k	(6,389)	0.00000	0	0.00000	0
Brokerage Fee: Noncore Marketing	l	(123)	0.14996	(18)	0.14996	(18)
Long Term Contract Revenue	a	(2,858)	0.09108	(260)	0.09250	(264)
SUBTOTAL - Adjusted Base		1,088,676		36,671		37,107
Pipe Demand Charges	6	176,496	0.08919	15,742	0.08919	15,742
Pipeline Demand Trueup	16	2,401	0.17038	409	0.17038	409
Gas Storage Carrying Costs	7	14,574	0.07256	1,057	0.07256	1,057
Gas Storage Trueup	17	1,708	0.17046	291	0.17046	291
Take-or-Pay Transition Costs	1	27,500	0.09102	2,503	0.09250	2,544
Take-or-Pay Trueup	1	20,467	0.09102	1,863	0.09250	1,893
CFA Debt Service and Expense	2	2,628	0.00000	0	0.00000	0
Gas Exploration & Development Account	1	50,000	0.09102	4,551	0.09250	4,625
LUAF & GDU	11	61,841	0.09601	5,937	0.09539	5,899
CPUC Fee	12	4,489	0.12833	576	0.12766	573
LIRA A&G	14	1,961	0.00000	0	0.00000	0
RD&D Trueup - Core	19	728	0.00000	0	0.00000	0
RD&D Trueup - Noncore	17	352	0.17046	60	0.17046	60
Noncore Base Cost Adjustment	17	(193)	0.17046	(33)	0.17046	(33)
1990 ACAP F&U Adjustment	20	(1,021)	0.16429	(168)	0.16429	(168)
Corporate Franchise Tax Adjustment	21	(289)	0.16743	(48)	0.16743	(48)
Earthquake Recovery Adjustment	n	486	0.15157	74	0.16313	79
TOTAL - Forecasted Period Costs		1,452,804		69,485		70,030
AMORTIZATION OF BALANCING ACCOUNTS						
Gas Core Fixed Cost	3	49,873	0.00000	0	0.00000	0
Noncore Transition Cost	9	(2,699)	0.15843	(428)	0.16423	(443)
Enhanced Oil Recovery	5	(2,492)	0.04172	(104)	0.04172	(104)
A&S Interutility	6	(109)	0.08919	(10)	0.08919	(10)
CFA Debt Service and Expense	2	(1,327)	0.00000	0	0.00000	0
Core TOP	3	0	0.00000	0	0.00000	0
NGV	1	0	0.09102	0	0.09250	0
LIRA	14	(8,277)	0.00000	0	0.00000	0
COGEN Shortfall	13	1,106	0.31133	344	0.30918	342
TOTAL - Forecasted Acct Balances		36,075		(197)		(215)
F&U		13,793		647		653
TOTAL - Transport Revenue Requirement		1,502,672		69,935		70,468
ALLOCATION ADJUSTMENTS						
G-10 Allocated Employee Discount	18	969	0.03409	33	0.03409	33
GC-2 Shortfall		(7,941)		(2,313)		(2,313)
GC-2 Shortfall Allocated	8	7,941	0.08379	665	0.08510	676
LIRA Discount Benefits		(17,268)		0		0
LIRA Discount Expenses	14	17,268	0.00000	0	0.00000	0
TOTAL - Transport Costs		1,503,641		68,321		68,864

TABLE 12

PACIFIC GAS AND ELECTRIC COMPANY
WHOLESALE CUSTOMERS COST ALLOCATION

Forecast Period: April 1, 1991 to March 31, 1992

	ALLOC INDEX	SYSTEM COST ($000)	UNADJ ALLOC FACTOR	UNADJ COST ($000)	ADJ ALLOC FACTOR	ADJ COST ($000)
FORECAST PERIOD COSTS						
Commodity Related Base	a	10,145	0.01894	192	0.01941	197
Transmission Base	e	212,600	0.01938	4,120	0.01984	4,218
Storage Base	c	43,869	0.02342	1,027	0.02396	1,051
Distribution Base	d	276,945	0.00000	0	0.00000	0
Customer Base	b	499,381	0.00043	214	0.00043	214
50% Adminstrative and General	m	88,634	0.01006	892	0.01031	914
Other Operating Revenue	f	(9,149)	0.00568	(52)	0.00582	(53)
SUBTOTAL - Base (Margin)		1,122,424		6,393		6,540
EOR Credit	h	(12,187)	0.00753	(92)	0.00771	(94)
Interutility Transportation Service	e	(6,893)	0.01938	(134)	0.01984	(137)
Brokerage Fee: Procurement A&G	j	(5,298)	0.03302	(175)	0.03447	(183)
Brokerage Fee: Core Marketing	k	(6,389)	0.00000	0	0.00000	0
Brokerage Fee: Noncore Marketing	l	(123)	0.02134	(3)	0.02134	(3)
Long Term Contract Revenue	a	(2,858)	0.01894	(54)	0.01941	(55)
SUBTOTAL - Adjusted Base		1,088,676		5,936		6,069
Pipe Demand Charges	6	176,496	0.01984	3,502	0.01984	3,502
Pipeline Demand Trueup	16	2,401	0.03790	91	0.03790	91
Gas Storage Carrying Costs	7	14,574	0.02396	349	0.02396	349
Gas Storage Trueup	17	1,708	0.05629	96	0.05629	96
Take-or-Pay Transition Costs	1	27,500	0.01891	520	0.01941	534
Take-or-Pay Trueup	1	20,467	0.01891	387	0.01941	397
CFA Debt Service and Expense	2	2,628	0.00000	0	0.00000	0
Gas Exploration & Development Account	1	50,000	0.01891	946	0.01941	971
LUAF & GDU	11	61,841	0.01877	1,161	0.01884	1,165
CPUC Fee	12	4,489	0.00000	0	0.00000	0
LIRA A&G	14	1,961	0.00000	0	0.00000	0
RD&D Trueup - Core	19	728	0.00000	0	0.00000	0
RD&D Trueup - Noncore	17	352	0.05629	20	0.05629	20
Noncore Base Cost Adjustment	17	(193)	0.05629	(11)	0.05629	(11)
1990 ACAP F&U Adjustment	20	(1,021)	0.03170	(32)	0.03170	(32)
Corporate Franchise Tax Adjustment	21	(289)	0.02733	(8)	0.02733	(8)
Earthquake Recovery Adjustment	n	486	0.00000	0	0.00000	0
TOTAL - Forecasted Period Costs		1,452,804		12,956		13,143
AMORTIZATION OF BALANCING ACCOUNTS						
Gas Core Fixed Cost	3	49,873	0.00000	0	0.00000	0
Noncore Transition Cost	9	(2,699)	0.03292	(89)	0.03447	(93)
Enhanced Oil Recovery	5	(2,492)	0.00754	(19)	0.00754	(19)
A&S Interutility	6	(109)	0.01984	(2)	0.01984	(2)
CFA Debt Service and Expense	2	(1,327)	0.00000	0	0.00000	0
Core TOP	3	0	0.00000	0	0.00000	0
NGV	1	0	0.01891	0	0.01941	0
LIRA	14	(8,277)	0.00000	0	0.00000	0
COGEN Shortfall	13	1,106	0.00000	0	0.00000	0
TOTAL - Forecasted Acct Balances		36,075		(110)		(114)
F&U		13,793		108		96
TOTAL - Transport Revenue Requirement		1,502,672		12,954		13,125
ALLOCATION ADJUSTMENTS						
G-10 Allocated Employee Discount	18	969	0.00556	5	0.00556	5
GC-2 Shortfall		(7,941)		0		0
GC-2 Shortfall Allocated	8	7,941	0.01933	153	0.01985	158
LIRA Discount Benefits		(17,268)		0		0
LIRA Discount Expenses	14	17,268	0.00000	0	0.00000	0
TOTAL - Transport Costs		1,503,641		13,113		13,288

TABLE 13

PACIFIC GAS AND ELECTRIC COMPANY

UEG/COGEN PARITY

Forecasted Period: April 1, 1991 to March 31, 1992

UEG FIXED COST (000's)		$128,552	
UEG IGNITER FUEL FIXED COST		4,403	
COGEN FIXED COST (EXCLUDING GC-2)		65,059	
TOTAL UEG/IGNITER FUEL/COGEN FIXED COST			$198,015
UEG SUPPLY FORECAST (Mth)	1,462,600		
IGNITER FUEL FORECAST (Mth)	14,450		
UEG VOLUMES (Mth)		1,477,050	
COGEN SUPPLY FORECAST	696,000		
GC-2	(66,000)		
MOJAVE LONG TERM CONTRACT	(35,000)		
UNADJUSTED COGEN VOLUMES		595,350	
COGEN DISCOUNT ADJ FACTOR		0.99000	
COGEN VOLUMES (EXCLUDING GC-2)		589,000	
TOTAL UEG/IGNITER FUEL/COGEN VOLUMES			2,066,000
UEG/COGEN AVERAGE RATE ($/th)			0.09435

COGEN FIXED COST RESPONSIBILITY			
SUPPLY FORECAST (Mth)	589,397		
UEG/IGNITER FUEL/COGEN AVE RATE ($/th)	0.09584		
		$56,452	
GC-2 CONTRACT REVENUE		3,805	
TOTAL COGEN FIXED COST RESPONSIBILITY			$60,257

UEG FIXED COST RESPONSIBILITY (G-UEG)		
UEG/IGNITER FUEL/COGEN FIXED COST	$198,015	
COGEN FIXED COST RESPONSIBILITY	(56,452)	
IGNITER FUEL FIXED COST	(4,403)	
TOTAL UEG FIXED COST RESPONSIBILITY		$137,159
UEG AVERAGE RATE ($/TH)		$0.09378

UEG/IGNITER FUEL FIXED COST RESPONSIBILITY		
UEG/IGNITER FUEL/COGEN FIXED COST	$198,015	
COGEN FIXED COST RESPONSIBILITY	(56,452)	
UEG/IGNITER FUEL FIXED COST RESPONSIBILITY		$141,562
UEG/IGNITER FUEL AVE RATE ($/TH)		0.09584

TABLE 14

PACIFIC GAS AND ELECTRIC COMPANY
GC-2 CONTRACT SHORTFALL

Forecast Period: April 1, 1991 to March 31, 1992

INDUSTRIAL GC-2 SUPPLIES (Mth)				91,170
TRANSPORT COST BEFORE ALLOC ADJ (000'S)			$184,591	
STEAM HEAT (Mth)		10,860		
NONCORE INTERDEPARTMENTAL		1,030		
INDUSTRIAL GC-2		91,170		
INDUSTRIAL G-IND	1,383,430			
UEG-SCE	239,000			
	1,622,430			
INDUSTRIAL DISCOUNT ADJ	0.89882			
DISCOUNT ADJUSTED INDUSTRIAL		1,458,273		
TOTAL DISC ADJ INDUSTRIAL & INDUSTRIAL GC-2 (Mth)			1,561,333	
STANDARD INDUSTRIAL RATE BEFORE ALLOC ADJ ($/th)				0.11823
ALLOCATED INDUSTRIAL GC-2 FIXED COST RESPONSITILITY (000's)				$10,779
INDUSTRIAL GC-2 CONTRACT REVENUE				5,150
INDUSTRIAL GC-2 REVENUE SHORTFALL				$5,629

COGEN GC-2 SUPPLIES (Mth)				65,650
UEG TRANSPORT COST BEFORE ALLOC ADJ (000'S)			$126,821	
COGEN TRANSPORT COST BEFORE ALLOC ADJ (000'S)			70,468	
UEG (Mth)		1,462,600		
COGEN GC-2		65,650		
COGEN G-COG	629,880			
MOJAVE LONG TERM CONTRACT	(35,000)			
	594,880			
COGEN DISCOUNT ADJUSTMENT	0.99000			
DISCOUNT ADJUSTED COGEN		588,931		
TOTAL DISC ADJ UEG, COGEN & COGEN GC-2 (Mth)			2,117,181	
STANDARD UEG/COGEN RATE BEFORE ALLOC ADJ ($/th)				0.09318
ALLOCATED COGEN GC-2 FIXED COST RESPONSITILITY (000's)				$6,118
COGEN GC-2 CONTRACT REVENUE				3,805
COGEN GC-2 REVENUE SHORTFALL				$2,313

TOTAL INDUSTRIAL AND COGEN GC-2 CONTRACT SHORTFALL 7,941

TABLE 15

PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED DISCOUNT FACTORS

Forecast Period: April 1, 1991 to March 31, 1992

RATE SCHEDULE	DISCOUNT FACTOR *
G-IND (excluding SCE Cool Water)	98%
G-P2B	97%
G-COG	99%

* Per negotiated stipulation.

TABLE 16A

PACIFIC GAS AND ELECTRIC COMPANY
CORE RATES AND REVENUES

Forecast Period: April 1, 1991 to March 31, 1992

CLASS OF SERVICE	FORECAST REVENUES USING PRESENT RATES EFFECTIVE 1/1/91			FORECAST REVENUES USING RATES EFFECTIVE 4/1/91			ADOPTED CHANGE	
	(MTH/CUST)	($/TH)	(M$)	(MTH/CUST)	($/TH)	(M$)	($/TH)	(%)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
RES. NON-LIRA								
Tier I (Baseline)	1,497,668	0.50654	758,629	1,497,668	0.51337	768,858	0.00683	1.3
Tier II	476,314	0.82672	393,778	476,314	0.83355	397,032	0.00683	0.8
GS,GT Adjustment			(4,394)			(4,394)		
Subtotal Non-LIRA	1,973,982	0.58157	1,148,013	1,973,982	0.58840	1,161,496	0.00683	1.2
RES. LIRA								
Tier I (Baseline)	144,776	0.42587	61,656	144,776	0.43421	62,865	0.00834	2.0
Tier II	49,529	0.69803	34,573	49,529	0.70637	34,986	0.00834	1.2
Subtotal LIRA	194,305	0.49524	96,228	194,305	0.50358	97,849	0.00834	1.7
Total Residential (1)	2,168,287	0.57384	1,244,242	2,168,287	0.58080	1,259,345	0.00697	1.2
SCHEDULE G-NR1 (2)								
Customer Charge	198,232	12.11 /MO	28,806	198,232	12.06 /MO	28,687	(0.05)/MO	(0.4)
Summer Rate (3)	363,960	0.48656	177,088	363,960	0.47909	174,370	(0.00747)	(1.5)
Winter Rate (4)	402,790	0.65686	264,577	402,790	0.64677	260,512	(0.01009)	(1.5)
Total G-NR1	766,750	0.61359	470,471	766,750	0.60459	463,569	0.00900	(1.5)
SCHEDULE G-NR2 (5)								
Customer Charge	455	138.41 /MO	756	455	139.40 /MO	759	0.99 /MO	0.7
Summer Rate (3)	71,664	0.43689	31,309	71,664	0.42525	30,475	(0.01164)	(2.7)
Winter Rate (4)	80,363	0.58979	47,397	80,363	0.57409	46,135	0.01570	(2.7)
Total G-NR2	152,027	0.52269	79,462	152,027	0.50892	77,369	(0.01377)	(2.6)
SCHEDULE G-NR3 (6)								
Customer Charge	6.00	138.41 /MO	10	6.00	139.40 /MO	10	0.99 /MO	0.7
Summer Rate (3)	1,946	0.19233	374	1,651	0.19301	376	(0.00068)	(0.4)
Winter Rate (4)	2,187	0.34523	755	2,483	0.34185	7,488	(0.00338)	(1.0)
Total G-NR3	4,133	0.27566	1,139	4,134	0.27421	1,133	(0.00145)	(0.5)
SCHEDULE G-NGV1 (7)								
Customer Charge	6.25	8.35 /MO	1	6.25	11.99 /MO	1	3.64 /MO	43.6
Volumetric Rate	28	0.47514	13	28	0.51099	14	0.03585	7.5
Total G-NGV1	28	0.49751	14	28	0.54311	15	0.04560	9.2
SCHEDULE G-NGV2 (7)								
Customer Charge	35.00	8.35 /MO	4	35.00	11.99 /MO	5	3.64 /MO	43.6
Volumetric Rate	523	0.59123	309	523	0.61406	321	0.02283	3.9
Total G-NGV2	523	0.59794	313	523	0.62369	326	0.02575	4.3
Total Commercial (7)	922,910	0.59710	551,073	922,911	0.58735	542,071	(0.00975)	-1.6
TOTAL CORE (7)	3,091,197	0.58078	1,795,314	3,091,197	0.58276	1,801,416	0.00197	(0.3)

TABLE 16B

PACIFIC GAS AND ELECTRIC COMPANY
FOOTNOTES TO CORE RATES AND REVENUES

Forecast Period: April 1, 1991 to March 31, 1992

(1) Adjusted for G-10 sales 4,173 Mth.

(2) Applicable to P1, P2A and P2B commercial customers with use of fewer than 20,800 therms per active month. All therms sold at G-PC, $.23224 per therm. Includes interdepartmental construction clearing and other operating sales.

(3) April through October.

(4) November through March.

(5) Applicable to P1 and P2A commercial customers with use of 20,800 therms per active month. All therms sold at G-PC ($.23224 per therm.)

(6) Applicable to P1 and P2A commercial customers with use of 20,800 therms per active month. G-NR3 schedule is a transportation-only schedule. Customers may contract for core-elect procurement, noncore procurement, or select a third-party procurement service.

(7) Volumes, rates, and revenues for NGV-1 and NGV-2 are shown for illustrative purposes only and are not included in any calculations affecting proposed rates.

TABLE 17A

PACIFIC GAS AND ELECTRIC COMPANY
NONCORE TRANSPORT RATES AND REVENUES

Forecast Period: April 1, 1991 to March 31, 1992

CLASS OF SERVICE	FORECAST REVENUES USING PRESEN RATES EFFECTIVE 1/1/91 (MTH/CUST)	($/TH)	(M$)	FORECAST REVENUES USING RATES EFFECTIVE 4/1/91 (MTH/CUST)	($/TH)	(M$)	ADOPTED CHANGE ($/TH)	(%)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
G-P2B (1)(15)								
Customer Charge	190	183.15 /MO	418	190	206.83 /MO	472	23.68 /MO	12.9
Demand Charge 1 (3)	165,931	0.05729	9,506	165,931	0.04953	8,219	(0.00776)	(13.5)
Demand Charge 2 (4)								
Summer (5)	133,359	0.01611	2,148	133,358	0.01401	1,868	(0.00210)	(13.1)
Winter (6)	97,526	0.02774	2,705	97,525	0.02286	2,230	(0.00488)	(17.6)
Volumetric Charge	169,905	0.06456	10,969	169,905	0.05358	9,103	(0.01098)	(17.0)
Total G-P2B - Std. Rate:	169,905	0.15154	25,747	169,905	0.12884	21,891	(0.02270)	(15.0)
G-IND (2)(15)								
Customer Charge	698	782.62 /MO	6,558	698	564.48 /MO	4,730	(218.14)/MO	(27.9)
Demand Charge 1 (3)	1,495,920	0.04448	66,539	1,488,867	0.04576	68,133	0.00128	2.9
Demand Charge 2 (4)								
Summer (5)	1,385,239	0.00796	11,027	1,436,038	0.00776	11,148	(0.00020)	(2.5)
Winter (6)	1,053,961	0.01676	17,664	1,064,767	0.01696	18,061	0.00020	1.2
Volumetric Charge (7)(13)	1,469,429	0.06201	91,121	1,470,226	0.05397	79,350	(0.00804)	(13.0)
G-IND - Std. Rate	1,469,429	0.13128	192,908	1,470,226	0.12340	181,422	(0.00789)	(6.0)
Plus GC-2	91,170		5,150	91,170		5,150		
Total Industrial	1,560,599	0.12691	198,058	1,561,386	0.11949	186,572	(0.00742)	(5.8)
UTILITY ELECTRIC GENERATION								
Customer Charge	1	100,875 /MO	1,211	1	77,562 /MO	931	(280)M$	(23.1)
Demand Charge (9)			107,903			96,508	(11,395)M$	(10.6)
Volumetric Charge								
Tier I (10)	242,137	0.06471	15,669	270,581	0.05208	14,091	(0.01263)	(19.5)
Tier II (11)	1,220,463	0.02767	33,770	1,192,019	0.02151	25,636	(0.00616)	(22.3)
Total G-UEG	1,462,600	0.10840	158,553	1,462,600	0.09378	137,166	(0.01462)	(13.5)
COGENERATION (15)								
G-COG - Std. Rate	588,931	0.10918	64,299	588,931	0.09585	56,446	(7,853)	(12.2)
Plus GC-2	65,650		3,805	65,650		3,805		
Total Cogeneration	654,571	0.10404	68,104	654,571	0.09205	60,251	(7,853)	(11.5)
SUBTOTAL								
(Net of GC-2):	3,690,856	0.11962	441,507	3,691,653	0.10752	396,925	(0.01210)	(10.1)
(Including GC-2):	3,847,676	0.11707	450,462	3,848,473	0.10547	405,880	(0.01161)	(9.9)
WHOLESALE (12)								
Demand Charge (9)			9,495			11,501	2,006 M$	21.1
Volumetric Charge	137,390	0.01330	1,827	137,390	0.01301	1,788	(0.00029)	(2.2)
Total Wholesale	137,390	0.08241	11,322	137,390	0.09672	13,288	0.01431	17.4
TOTAL NONCORE (14)								
(Net of GC-2):	3,828,246	0.11829	452,829	3,829,043	0.10713	410,213	(0.01115)	(9.4)
(Including GC-2):	3,985,066	0.11588	461,784	3,985,863	0.10516	419,168	(0.01071)	(9.2)

TABLE 17B

PACIFIC GAS AND ELECTRIC COMPANY
FOOTNOTES FOOTNOTES TO NONCORE TRANSPORT RATES AND REVENUES

Forecast Period: April 1, 1991 to March 31, 1992

(1) Includes P2B customers with use of at least 250,000 therms per year or 20,800 therms per active month.
(2) Also includes interdepartmental, steam heat, SCE Cool Water throughput.
(3) Based on a 12-month moving average.
(4) Based on a seasonal peak month ratchet. Charge is applied to the higher of the current month's use or use in another month in the same season in the previous 11 months.
(5) April through October
(6) November through March
(7) Applied to current month's use. Present revenue is calculated based on a weighted average volumetric rate of $.06201/th to account for those G-IND customers paying no CPUC fee.
(8) Applies to PG&E power plant noncore use.
(9) Monthly payments determined proportional to forecasted monthly volume.
(10 22,548,417 therms per month. The present rate reflects the current tier I volumes rather than the tier I volumes proposed.
(11) Applies to all volumes in excess of tier I.
(12) Currently schedule G-WRT.
(13) Reserved for future use.
(14) CPUC Fee revenue of M$371 for EOR/EORCOG class is not included in revenues at present rates column.
(15) The volumetric billing determinants are different for G-IND between Present Rates and Proposed Rates. This occurs because a portion of SCE's load is priced at PG&E's standard G-IND rate for purposes of estimating the required discount. The required discount is different between present and proposed rates because the average standard rates differ by $.00788 per therm. Billing determinants for P2B and Cogeneration classes are the same for both present and forecast revenues because the same level of discounting is assumed to occur in both instances.

(END OF APPENDIX C)

APPENDIX D
Page 1

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY for authority to revise its gas rates and tariffs effective April 1, 1991, pursuant to Decision Nos. 87-12-039, 88-01-040, 89-05-073, and 90-04-021 (U 39 G) (GAS)	Application No. 90-08-029

STIPULATION BETWEEN PACIFIC GAS AND ELECTRIC COMPANY, THE DIVISION OF RATEPAYER ADVOCATES, THE CANADIAN PRODUCER GROUP, THE CITY OF PALO ALTO, SOUTHERN CALIFORNIA EDISON COMPANY, AND TOWARD UTILITY RATE NORMALIZATION

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November 27, 1990

APPENDIX D
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STIPULATION
BETWEEN
PACIFIC GAS AND ELECTRIC COMPANY,
THE DIVISION OF RATEPAYER ADVOCATES, THE CANADIAN PRODUCER GROUP, THE CITY OF PALO ALTO, SOUTHERN CALIFORNIA EDISON COMPANY, AND TOWARD UTILITY RATE NORMALIZATION

**STIPULATION
BETWEEN
PACIFIC GAS AND ELECTRIC COMPANY,
THE DIVISION OF RATEPAYER ADVOCATES, THE CANADIAN PRODUCER GROUP, THE CITY OF PALO ALTO, SOUTHERN CALIFORNIA EDISON COMPANY, AND TOWARD UTILITY RATE NORMALIZATION**

The parties to this stipulation (Stipulation) are Pacific Gas and Electric Company (PG&E), the Division of Ratepayer Advocates (DRA), the Canadian Producer Group (CPG), the City of Palo Alto (Palo Alto), Southern California Edison Company (SCE), and Toward Utility Rate Normalization (TURN).

PG&E, DRA, CPG, Palo Alto, SCE and TURN are collectively referred to herein as the "Parties," and individually referred to herein as a "Party."

The Parties have entered into this Stipulation to resolve among themselves many of the issues in PG&E's Application No. 90-08-029, PG&E's 1991-1992 test year ACAP proceeding.

The Parties believe that this Stipulation is a reasonable compromise of their opposing positions, especially in light of the current substantial uncertainty surrounding world oil markets caused by current events in the Middle East, and the fact that D. 90-09-89 in the

Procurement OIR is expected to be implemented during the test period.

Therefore, the undersigned Parties, through their Attorneys of Record in this proceeding, agree to this Stipulation, jointly support the recommendations described below for resolution of issues in this proceeding, and jointly urge their adoption in this proceeding by the California Public Utilities Commission.

I.

ISSUES NOT COVERED BY THE STIPULATION

This Stipulation does not address the following issues:

1. PG&E's proposal to establish rates for Rate Schedule G-COG on a forecast basis;

2. PG&E's request to recover the outstanding balance in the Cogeneration Shortfall Account; and

3. PG&E's proposal to treat long-term contract revenues as a credit to base revenues and to allocate that credit based on equal cents per therm.

II.

RECOMMENDATIONS

A. Total Revenue Requirement and Rates

The recommendations presented in Sections B through H, below, result in a revenue requirement decrease of $42.3 million, as indicated in Table 1 attached to this Stiplation[1]. The rates shown in Tables 2 and 3 result from (1) the revenue requirement presented in Table 1, (2) the throughput forecasts presented in Tables 4 and 5, and (3) the recommendations presented in Sections B through H, below.

Except as expressly stated in Sections B through H below, those assumptions necessary for the derivation of revenues at present rates, the revenue requirement and/or of rates are as set forth in PG&E's Prepared Testimony. The

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[1] The calculation of this revenue requirement includes assumptions regarding the resolution of the outstanding issues listed in Section I, above. In each case PG&E's position in its Prepared Testimony is assumed for purposes of developing the revenue requirement table. While none of these issues will have a significant impact on the rates presented in Tables 2 and 3, rates reflecting the Commission's resolution of these issues may be slightly different.

In any event, the revenue requirement table and the resulting rate tables do not represent the final rates the Commission would adopt through adoption of this Stipulation. One component of the Stipulation is that, consistent with the approach taken in last years's ACAP, the Parties recommend that the revenue requirement be updated in accordance with PG&E's update proposal set forth in Chapter 1 of PG&E's Prepared Testimony.

Parties recommend that, with the exception of the issues not addressed by this Stipulation, listed in Section I, above, the Commission adopt those assumptions which are embodied in Tables 1 through 5. With respect to those issues the resolution of which are not necessary for the derivation of revenues at present rates, the revenue requirement and/or of rates, the Parties recommend that no assumptions be adopted, except as recommended below in Sections B through H.

B. <u>Economic and Oil Price Inputs</u>

The Parties recommend that the Commission not adopt any specific forecast of the Refiners' Acquisition Cost of crude oil (RAAC) during the test period. The Parties recognize the substantial uncertainty surrounding any forecast of the RAAC price. Therefore, instead of forecasting a RAAC price and using it to derive the expected level of discounting to noncore customers, the Parties have developed specific discounting recommendations for the G-IND, G-P2B and G-COG classes, set forth in Section F, below. These discounting recommendations embody an implicit assumption that the RAAC price for the test period is expected to be high enough to require only a minimal level of discounting.

C. Gas Throughput Forecast

The Parties recommend the adoption of the gas demand, curtailment, and resulting throughput forecasts reflected in Tables 4 and 5 for average and cold years, respectively. The monthly level for curtailments has been derived by scaling the total levels of curtailment represented in Tables 4 and 5 by the monthly estimates of curtailment provided in PG&E's Prepared Testimony.

The Parties recommend that the cold year wholesale throughput forecast be 6% greater than the wholesale throughput forecast contained in PG&E's Prepared Testimony, and that this additional throughput all be added during the winter months.

The Parties recommend an interutility forecast of 50 million decatherms, consisting of a forecast of 3.9 million decatherms of California source interutility throughput and a forecast of 46.1 million decatherms of interutility throughput from Topock to Kern River.

D. Gas Supply Sources, Portfolios, and Related Matters

The Parties recommend a forecast of $2.23 per decatherm for the core portfolio WACOG, and a forecast of $2.52 per decatherm for the noncore portfolio WACOG. These values do not include franchise fees and uncollectible accounts expense or brokerage fees.

The Parties recommend, in light of the FERC Order 528, that the Commission adopt an estimate of El Paso Order No. 500 direct-billed take-or-pay expenses of $27.5 million.

The core portfolio WACOG recommended by this Stipulation presumes continuation of preferential sequencing of PGT supplies, at a minimum until August 1, 1991, and, if current competitive conditions continue, for the remainder of the test period, based on comparisons of average gas costs utilizing (1) realistic interstate pipeline load factors, and (2) realistic interstate pipeline capacity availabilities.

E. Revenue Requirement and Results of Operation

The Parties recommend that a 90% balancing account be instituted for noncore transportation revenues. Specifically, the Parties recommend that 90% of any variation between the noncore transportation revenues, excluding those revenues amortizing balances in existing balancing accounts, and the adopted noncore revenue requirement, excluding balances of existing balancing accounts, be placed into an interest-bearing balancing account. The allocation between classes of the balance in this balancing account will be decided in PG&E's next cost allocation proceeding.

The Parties recommend that this balancing account become effective on the same date that the rate change resulting from this application becomes effective, currently anticipated to be April 1, 1991, and that the 90% balancing account remain in effect until the implementation of rates resulting from PG&E's next cost allocation proceeding, currently anticipated to be April 1, 1992. At that time, absent explicit Commission direction to the contrary, the 90% balancing account will be discontinued, and the 75% noncore transportation revenue balancing account adopted in D. 90-09-089 in the Procurement OIR will be placed in effect.

The Parties recommend that the EOR, NRSA and CFA balancing account balances be adjusted to reflect the recommendations of the DRA audit of those accounts. Specifically, the Parties recommend that the balance in the allowance for doubtful accounts within the Conservation Financing Adjustment debt service and expense balancing account be lowered to 5.4% of the outstanding loan portfolio balance as of the effective date of the decision, that the NRSA balance be decreased by $4.535 million, and that the

EOR balancing account be decreased by $319,222. The Parties recommend that RD&D costs of $1.08 million be allocated $.728 million to core and $.352 million to noncore, and that the Core Gas Fixed Cost Account balance and the NRSA balance, respectively, be decreased to reflect the RD&D amounts.

The Parties recommend that the estimate of the PGT refund be updated to $6.8 million to reflect the amount actually received by PG&E.

The Parties recommend the adoption of PG&E's proposals in its Prepared Testimony to consolidate several balancing accounts.

The Parties recommend that the balance in the NGV memorandum account not be included in the revenue requirement in this year's ACAP. Rather, the Parties recommend that the amount remain in the memorandum account, to be allocated in PG&E's next cost allocation proceeding.

F. <u>Market Response and the Discount Adjustment Methodology</u>

The Parties recommend that the Commission adopt the following discount adjustment factors: G-IND excluding Cool Water, 98%; G-P2B, 97%; and G-COG, 99%.

These discount factors represent an explicit recognition of continuing but extremely limited discounting to G-IND customers excluding Cool Water.

Additionally, the Parties recommend that revenues from the Cool Water power plant be forecast as follows: 6 million decatherms at the average G-IND default rate, and the remaining 17.9 million decatherms at the Southern California Gas Company Tier II UEG rate of 29.15 cents per decatherm.

These discount factors also exclude the volumes associated with the long term contract (Mojave) which has been approved by the Commission[2]. The Parties recommend that the volumes associated with the two pending long term contracts (Luz and C&H), which were filed by way of advice letter, be treated in the same manner only if the Commission approves these contracts prior to the update. Otherwise, if those contracts are not approved, the parties

[2] The method of treating the revenues associated with long term contracts is not addressed by this Stipulation. (see Section I). The revenues from this contract are being treated as a revenue credit in the Tables attached to this Stipulation.

recommend that the associated volumes be included in the throughput forecast for the appropriate rate classes[9].

G. Cost Allocation

The Parties recommend that the Commission adopt the cost allocation methods presented by PG&E in its Prepared Testimony, with the exception of (1) those cost allocation issues identified in Section I above, and (2) the allocation of the NGV credit.

H. Rate Design

The Parties recommend that the brokerage fee be established by dividing the brokerage revenue requirement by the unadjusted forecast of noncore and core-elect procurement volumes.

The Parties recommend that the residential tier differential be gradually reduced by the method proposed in PG&E's Prepared Testimony.

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[9] The throughput forecasts presented in Tables 4 and 5 include the volumes associated with the Mojave, Luz and C&H contracts.

III.

GENERAL TERMS

The Parties agree that in this proceeding no Party will contest, either by cross-examination of any Party witness on issues resolved among the Parties by this Stipulation, during briefing, or otherwise, the recommendations contained herein.

However, this shall not be construed to be an acceptance or endorsement of the principles, assumptions or methodologies underlying these recommendations. The Parties agree that the principles, assumptions and methodologies underlying the specific items addressed in this Stipulation are recommended for the purpose of this proceeding only, and are not to be deemed by the Commission or any other entity as precedent in any proceeding or litigation except as necessary to implement the recommendations contained herein in this proceeding.

The Parties expressly reserve the right to advocate in other proceedings principles, assumptions or methodologies different from those which may underlie or appear to be implied by this Stipulation.

Unless the Commission accepts this Stipulation and the recommendations it contains in their entirety, without change or condition, the Parties agree that the Stipulation shall be null and void.

The Parties intend and agree that this Stipulation is subject to each and every condition set forth, including its acceptance by the Commission in its entirety and without change or condition.

The Parties agree to extend their best efforts to insure the adoption of this Stipulation.

The undersigned Parties agree to this Stipulation through their Counsel Of Record in this proceeding.

Pacific Gas and Electric Company

By: ______________________ Date 11/27/90
MARK R. HUFFMAN

Division of Ratepayer Advocates

By: ______________________ Date 11/27/90
JOHN S. WONG

City of Palo Alto

By: ______________________ Date 11/27/90
ARIEL P. CALONNE

Canadian Producer Group

By: ______________________ Date 11/27/90
JOHN W. JIMISON MRH

Southern California Edison Company

By ______________________ Date 11/27/90
~~FRANK COOLEY~~
ANNETTE GILLIAM

Toward Utility Rate Normalization

By: ______________________ Date 11/27/90
MICHEL P. FLORIO

TABLE 1
PACIFIC GAS AND ELECTRIC COMPANY
REVENUE REQUIREMENT SUMMARY
11/27/1990

Line No.				Line
	PROCUREMENT REVENUE REQUIREMENT $(000)			
	Forecasted Gas Portfolio Costs:			
1	Core (includes Core-elect)	$1,388,117		1
2	Noncore	$73,211		2

3	Total Commodity Costs		$1,461,329	3
4	Brokerage Fees		$11,124	4
5	Core Purchased Gas Account Balance		$10,149	5
6	Franchise Fees and Uncollectible Accounts Expense		$13,270	6

7	Total Procurement Revenue Requirement		$1,495,871	7
8	Less: Procurement Revenues at Present Rates		$1,590,007	8

9	Change in Procurement Revenue Requirement		($94,136)	9
	TRANSPORTATION REVENUE REQUIREMENT			
	Forecast Period Costs:			
10	Base Amount	$1,070,783		10
11	EOR Credit	($12,187)		11
12	Interutility Credit	($6,893)		12
13	Brokerage Fee Credit	($11,224)		13
14	Long-Term Contract Credit	($2,924)		14
15	RD&D Trueup	$1,080		15
16	Pipeline Demand Charges	$176,496		16
17	Pipeline Demand Trueup	$3,290		17
18	Carrying Cost on Gas in Storage	$14,574		18
19	Storage Carrying Cost Trueup	$942		19
20	Take-or-Pay Transition Costs	$27,500		20
21	Take-or-Pay Trueup	$20,853		21
22	CFA Debt Service and Expense	$2,629		22
23	GEDA	$30,000		23
24	LUAF & GDU Gas	$61,841		24
25	CPUC Fee Expense	$4,489		25
26	LIRA	$1,961		26

27	Total Forecast Period Costs		$1,405,309	27
	Amortization of Balancing Account Balances:			
28	Core Gas Fixed Cost Account*	$107,099		28
29	Noncore Transition Cost Account	($11,102)		29
30	Enhanced Oil Recovery Account	($2,777)		30
31	A&S Interutility Balancing Account	($33)		31
32	CFA Debt Service and Expense	$774		32
33	Core T-O-P Balancing Account	$0		33
34	NGV Account	$0		34
35	LIRA Account Balance	($3,598)		35
36	CoGen Shortfall Account Balance	$1,140		36

37	Total Forecasted Account Balances		$91,503	37
38	Franchise Fees and Uncollectible Accounts Expense		$4,115	38

39	Total Transportation Revenue Requirement		$1,500,927	39
40	Less: Transportation Revenues at Present Rates		$1,449,091	40

41	Change in Transportation Revenue Requirement		$51,836	41
			===========	
42	Total Change in Revenue Requirement		($42,300)	42
			===========	

* Seasonally adjusted balance.

PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF CORE RATES AND REVENUES
1991 ACAP PROPOSED SETTLEMENT AGREEMENT

CLASS OF SERVICE	FORECAST REVENUES USING PRESENT RATES EFFECTIVE 4/19/90 Adj.Bill.Det.	Rate	Revenue	FORECAST REVENUES USING RATES EFFECTIVE 4/1/91 Adj.Bill.Det.	Rate	Revenue	CHANGE IN STANDARD RATES		LINE NO.
(A)	(B) (MTH/CUST #)	(C) ($/TH)	(D) (M$)	(E) (MTH/CUST #)	(F) ($/TH)	(G) (M$)	(H) ($/TH)	(I) (%)	
RES. NON-LIRA									
Tier I (Baseline)	1,497,668	.48950	733,108	1,497,668	.51767	775,298	.02817	5.8	1
Tier II	476,314	.80968	385,662	476,314	.83785	399,080	.02817	3.5	2
GS,GT Adjustment			-4,394			-4,394			3
Subtotal Non-LIRA	1,973,982	.56453	1,114,376	1,973,982	.59270	1,169,984	.02817	5.0	4
RES. LIRA									
Tier I (Baseline)	144,776	.41139	59,559	144,776	.43698	63,264	.02559	6.2	5
Tier II	49,529	.68355	33,856	49,529	.70913	35,122	.02558	3.7	6
Subtotal LIRA	194,305	.48076	93,415	194,305	.50635	98,386	.02558	5.3	7
Total Residential (1)	2,168,287	.55703	1,207,791	2,168,287	.58496	1,268,370	.02794	5.0	8
SCHEDULE G-NR1 (2)									
Customer Charge	198,232	11.37/MO	27,046	198,232	11.40/MO	27,117	.03/MO	.3	9
Summer Rate (3)	307,820	.47358	145,777	307,820	.47441	146,033	.00083	.2	10
Winter Rate (4)	458,930	.63934	293,412	458,930	.64045	293,922	.00111	.2	11
Total G-NR1	766,750	.60807	466,236	766,750	.60916	467,072	.00109	.2	12
CHEDULE G-NR2 (5)									
Customer Charge	455	129.84/MO	709	455	131.70/MO	718	1.86/MO	1.4	13
Summer Rate (3)	60,639	.42599	25,832	60,639	.41913	25,416	-.00686	-1.6	14
Winter Rate (4)	91,388	.57509	52,556	91,388	.56583	51,710	-.00926	-1.6	15
Total G-NR2	152,027	.52028	79,097	152,027	.51204	77,844	-.00824	-1.6	16
CHEDULE G-NR3 (6)									
Customer Charge	6.00	129.84/MO	9	6	131.70/MO	9	1.86/MO	1.4	17
Summer Rate (3)	1,651	.18143	300	1,651	.18728	309	.00585	3.2	18
Winter Rate (4)	2,483	.33053	821	2,483	.33398	829	.00345	1.0	19
Total G-NR3	4,134	.27325	1,130	4,134	.27769	1,148	.00444	1.6	20
CHEDULE G-NGV1 (7)									
Customer Charge	6.25	8.10/MO	1	6.25	11.33/MO	1	3.23/MO	39.9	21
Volumetric Rate	28	.45719	13	28	.54303	15	.08584	18.8	22
Total G-NGV1	28	.47889	13	28	.57338	16	.09449	19.7	23
CHEDULE G-NGV2 (7)									
Customer Charge	35.00	8.10/MO	3	35.00	11.33/MO	5	3.23/MO	39.9	24
Volumetric Rate	523	.57328	300	523	.65913	345	.08585	15.0	25
Total G-NGV2	523	.57978	303	523	.68948	349	.10969	18.9	26
otal Commercial (7)	922,911	.59211	546,462	922,911	.59168	546,064	-.00043	-.1	27
TAL CORE (7)	3,091,198	.56750	1,754,253	3,091,198	.58697	1,814,434	.01947	3.4	28

TABLE 3

PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF NONCORE TRANSPORT RATES AND REVENUES
1991 ACAP PROPOSED SETTLEMENT AGREEMENT

:NE).	NONCORE CUSTOMER CLASS	FORECAST REVENUES USING PRESENT RATES EFFECTIVE 4/19/90 Adj.Bill.Det.	Rate	Revenue	FORECAST REVENUES USING RATES EFFECTIVE 4/1/91 Adj.Bill.Det.	Rate	Revenue	CHANGE IN STANDARD RATES		Line No.
	(A)	(B) (MTH/CUST #)	(C) ($/TH)	(D) (M$)	(E) (MTH/CUST #)	(F) ($/TH)	(G) (M$)	(H) ($/TH)	(I) (%)	
	G-P28 (1)(15)									
	Customer Charge	190	171.80/MO	392	190	195.40/MO	446	23.60/MO	13.7	1
	Demand Charge 1 (3)	165,931	.05610	9,309	165,931	.04715	7,824	-.00895	-16.0	2
	Demand Charge 2 (4)									
	Summer (5)	133,359	.01522	2,030	133,358	.01422	1,896	-.00100	-6.6	3
	Winter (6)	97,526	.02621	2,556	97,525	.02097	2,046	-.00524	-20.0	4
	Volumetric Charge	169,905	.06282	10,673	169,905	.05258	8,934	-.01024	-16.3	5
	Total G-P28 - Std. Rate:	169,905	.14691	24,960	169,905	.12445	21,145	-.02246	-15.3	6
	G-IND (2)(15)									
	Customer Charge	698	734.87/MO	6,157	698	533.59/MO	4,471	-201.28/MO	-27.4	7
	Demand Charge 1 (3)	1,497,114	.04356	65,214	1,490,296	.04347	64,785	-.00009	-.2	8
	Demand Charge 2 (4)									9
	Summer (5)	1,386,935	.00753	10,444	1,437,407	.00823	11,826	.00070	9.3	10
	Winter (6)	1,054,965	.01585	16,721	1,065,782	.01565	16,678	-.00020	-1.3	11
	Volumetric Charge (7)(13)	1,470,672	.06037	88,786	1,471,628	.05304	78,052	-.00733	-12.1	12
	G-IND - Std. Rate	1,470,672	.12737	187,323	1,471,628	.11947	175,812	-.00790	-6.2	13
	Plus GC-2	91,170		4,888	91,170		4,888			14
	Total Industrial	1,561,842	.12307	192,211	1,562,798	.11563	180,700	-.00744	-6.0	15
	UTILITY ELECTRIC GENERATION									
	Customer Charge	1	96,167/MO	1,154	1	73,275/MO	879	-275M$	-23.8	16
	Demand Charge (9)			104,974			91,711	-13,263M$	-12.6	17
	Volumetric Charge									18
	Tier I (10)	242,137	.06385	15,460	270,581	.05055	13,679	-.01329	-20.8	19
	Tier II (11)	1,220,463	.02722	33,221	1,192,019	.02146	25,584	-.00576	-21.2	20
	Total G-UEG	1,462,600	.10585	154,809	1,462,600	.09015	131,853	-.01570	-14.8	21
	COGENERATION (15)									
	G-COG - Std. Rate	588,931	.10660	62,781	588,931	.09015	53,092	-9,689	-15.4	22
	Plus GC-2	65,690		3,622	65,690		3,622			23
	Total Cogeneration	654,621	.10144	66,403	654,621	.08664	56,714	-9,689	-14.6	24
	SUBTOTAL									
	(Net of GC-2):	3,692,108	.11643	429,873	3,693,064	.10341	381,902	-.01302	-11.2	25
	(Including GC-2):	3,848,968	.11390	438,383	3,849,924	.10141	390,412	-.01249	-11.0	26
	WHOLESALE (12)									
	Demand Charge (9)			9,317			10,993	1,676M$	18.0	27
	Volumetric Charge	137,390	.01275	1,752	137,390	.01304	1,792	.00029	2.3	28
	Total Wholesale	137,390	.08056	11,069	137,390	.09305	12,785	.01249	15.5	29
	TOTAL NONCORE (14)									
	(Net of GC-2):	3,829,498	.11514	440,942	3,830,454	.10304	394,687	-.01210	-10.5	30
	(Including GC-2):	3,986,358	.11275	449,452	3,987,314	.10112	403,197	-.01163	-10.3	31

TABLE 4

AVERAGE YEAR

GAS DEMAND AND THROUGHPUT FORECASTS
REFLECTING SETTLEMENT ADJUSTMENTS
(MMDTH)

Line No.	By Customer Class:	GAS DEMAND	CURTAILMENTS	GAS THROUGHPUT
	Core Throughput			
1	Residential	217.2	.0	217.2
2	Commercial	90.6	.0	90.6
3	Interdepartmental	.2	.0	.2
4	PG&E Start-up Fuel	1.4	.0	1.4
5	Total Core	309.5	.0	309.5
	Noncore Throughput			
6	Industrial (P2B) **	17.5	.0	17.5
7	Industrial (P3-4) **	138.3	.0	138.3
8	Industrial (GC-2)	9.1	.0	9.1
9	SCE Cool Water (G-IND)	23.9	.0	23.9
10	Steam Heat (G-IND)	1.1	.0	1.1
11	Interdepartmental (G-IND)	.1	.0	.1
12	Cogeneration (G-COG)	63.0	.0	63.0
13	Cogeneration (GC-2)	6.6	.0	6.6
14	EOR	50.6	1.8	48.8
15	Wholesale (G-WRT)	13.7	.0	13.7
16	Subtotal	323.9	1.8	322.1
17	UEG-PG&E	164.4	18.2	146.3
18	Total Noncore	488.4	20.0	468.4
	Other			
19	Gas Department Use	8.2	.0	8.2
20	Lost & Unacct For (LUAF)	17.5	.0	17.5
21	Total Other	25.7	.0	25.7
22	Total On-System	823.6	20.0	803.6
23	Interutility	50.0	.0	50.0
24	GRAND TOTAL	873.6	20.0	853.6

** Reflects a 3.0 percent increase in PG&E's original forecast.

TABLE 5

COLD YEAR

GAS DEMAND AND THROUGHPUT FORECASTS
REFLECTING SETTLEMENT ADJUSTMENTS
(MMDTH)

Line No.	By Customer Class:	GAS DEMAND	CURTAILMENTS	GAS THROUGHPUT
	Core Throughput			
1	Residential	249.0	.0	249.0
2	Commercial	99.5	.0	99.5
3	Interdepartmental	.2	.0	.2
4	PG&E Start-up Fuel	1.4	.0	1.4
5	Total Core	350.2	.0	350.2
	Noncore Throughput			
6	Industrial (P2B) **	17.5	.0	17.5
7	Industrial (P3-4) **	138.3	.0	138.3
8	Industrial (GC-2)	9.1	.0	9.1
9	SCE Cool Water (G-IND)	23.9	.0	23.9
10	Steam Heat (G-IND)	1.2	.0	1.2
11	Interdepartmental (G-IND)	.1	.0	.1
12	Cogeneration (G-COG)	63.0	.0	63.0
13	Cogeneration (GC-2)	6.6	.0	6.6
14	EOR	50.6	3.5	47.1
15	Wholesale (G-WRT)	14.6	.0	14.6
16	Subtotal	324.9	3.5	321.5
17	UEG-PG&E	164.4	33.5	130.9
18	Total Noncore	489.4	37.0	452.4
	Other			
19	Gas Department Use	8.8	.0	8.8
20	Lost & Unacct For (LUAF)	17.5	.0	17.5
21	Total Other	26.3	.0	26.3
22	Total On-System	865.9	37.0	828.9
23	Interutility	50.0	.0	50.0
24	GRAND TOTAL	915.9	37.0	878.9

** Reflects a 3.0 percent increase in PG&E's original forecast.

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused a copy of the STIPULATION BETWEEN PACIFIC GAS AND ELECTRIC COMPANY, THE DIVISION OF RATEPAYER ADVOCATES, THE CANADIAN PRODUCER GROUP, THE CITY OF PALO ALTO, SOUTHERN CALIFORNIA EDISON COMPANY, AND TOWARD UTILITY RATE NORMALIZATION in Application No. 90-08-029 to be mailed first-class to each of the parties of record in this proceeding.

Executed at San Francisco, California, this 27th day of November, 1990.

Grace Wong
GRACE WONG

(END OF APPENDIX D)