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Decision 91-05-029 May 8, 1991 4 %

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATEROF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY for authority to) ... revise its gas rates and tariffs effective April 1, 1991, pursuant to) . Application 90-08-029 Decision Nos. 87-12-039, 89-01-040,) (Filed August 15, 1990) 89-05-073, and 90-04-021. (U 39 G) Gas . ป<u>ัญหา Goo</u>fes อาเมื่อในได้ คือ อย**ีก**กลังปร

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This decision resolves issues raised in Pacific Gas and as Electric Company's (PG&E) third annual cost allocation proceeding a (ACAP). PG&E(s bundled core rates will decrease by .3%, or \$50 and million and its non-core transportation rates will decrease by 9.2% or \$42 million. and the second of the second o

We adopt in its entirety; a stipulation reached by the dead following parties: PG&E, the Division of Ratepayer Advocates and the second sec (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 control traditional ACAP issues and we find it is in the public interest. We commend the parties for settling most issues in light of the cost uncertainties over the Gulf war and the upcoming changes in the gas industry structure. The control of the small of the super-straight of the second

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

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The Procedural Background because the background

- PG&E filed its application in the above-captioned analysis proceeding on August 15, 1990, pursuant to the schedule set forth in Decision (D.) 89-01-040, the rulemaking which revised the time of schedule for rate cases and fuel offset proceedings. This is the on 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 an occur 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 of large customers have the market power to use cheaper options by the top 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 midSeptember. 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

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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. At the only party who wished to contest the stipulation was income agreement with the way the assigned ALJ handled the proceeding.

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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. 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 Itd. 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.

The state of the III. A Stipulation Issues are well and Indianal Alle

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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 crossexamine 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. Original Positions of Parties and a product

Due largely to the invasion of Kuwait by Iraq, PG&E was a 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 data 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.

pb. Stipulation Position and Date of the Company of the

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 hight 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.

particular in the control of the carbon models of the

c. Discussion

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 accounts: issue will be discussed in a later section of this decision.) -- We conagree 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, Control of the second of the second shall be adopted.

2. Cost of Natural Gas Walledown and Labelet MMM of Daw in the Daw

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 that the portfolio. They also have the option of purchasing gas from the control of purchasing someone other than the utility and transporting it over the utility system. Core ratepayers are indifferent as to whether or not noncore customers buy gas from the utility or someone else since the utility is required to sell the gas at cost. The utility's noncore 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 and approximately component of core rates. A second with the area of the properties of the

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 popular natural gas purchased by non-core transportation customers is a necessary:

a. In **Core Wacoc** and June 10 coming the U.J. Prester and disk and the

1) Original Positions of Parties () Program by the second

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 Date and Date and Date and Description

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. Allow 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

ا المحمد من الحجوج المحمد ا المحمد المحم percentage difference is fairly small to 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 of the contract of the contract

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 of a farming a content two bullets and but the

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.

3.40 Gas: Throughput: Forecast we release the commence this commence

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 throughout the same and the same

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 and 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.

The state of the s

(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 of these categories. A month of these categories.

5): TRG Throughput and another the common papers are

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.

Fig. 6) Curtailments (Million of the Million of the

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 13.70MMDth for wholesale throughput. Therefore this figure was incorporated in the stipulation.

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The stipulation non-core throughput figures are associated 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 tob non-core throughput forecast as set forth in the stipulation. WBy By adopting these non-core throughput numbers we give them nove differs precedential significance for future proceedings before the and the Commission: We agree that the parties, where there was a second disagreement, reached reasonable compromises given their overall Vot desire to settle this proceeding. The Annal Control of the Annal Control of the C

b. Core Throughput

1) Residential and Commercial Throughput

PG&E's and DRA's forecast of throughput forms () of the 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 formal commercial throughput, PG&E forecasted 90.6 MMDth while DRAFGE TO TO forecasted 91.1 MMDth. The stipulating parties adopted PG&E's was original positions. The stipulation residential throughput forecast, therefore, is 217.2 MMDth and its commercial throughput forecast is 90.6 MMDth. A substitute and March School Company the or

2) Core Interdepartmental and PG&E Transplant to the latest terms of the latest terms WEG Startup Fuel Throughput

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

3) Discussion and with the control of Mades Tenjaherband

Given the lack of controversy over all the core (2007) throughput numbers both in original testimony and in the or a convenience of the convenie stipulation, we will adopt the stipulation forecast as described to in the contraction of the contra above. To do otherwise would create controversy were there is none. The create and applied that there is

the trace of Shrinkage and the new colors all the telephones wide from the

department use and lost and unaccounted for usage (LAUF). CDDRA 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.

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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 are 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. gather the stipulation places the additional throughput in the wintermonths.

 $m{x}^*$ and $m{x}^*$ $m{y}^*$, $m{x}^*$ $m{y}^*$, $m{x}^*$ $m{y}^*$, $m{x}^*$

2) Cold Year Curtailments

In its original testimony PG&E forecasted 4.7 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 of the state of t

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.

e. 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; DRAWforecasted 53 MMDth; Or 6 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. And the statement of the contract o

Additionally the stipulating parties agreed to an array of 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 the state of the control of the state of the 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. The second is the second of the second of

41 Revenue Requirement and the last of the second distance and

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The total revenue requirement is the amount which PG&E ... requests to be recovered from customers during the ACAP periods was This includes both the revenue requirement related to gase of the over 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. The Foreign 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

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the text of this decision to describe the various credits and read balancing accounts that are uncontroversial in this proceeding. They will be listed in the tables attached to this decision. (See Appendix CD)

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 a 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 present the parties that the parties were allowed to present the parties that the parties were allowed the parties that the parties were allowed to present the parties that the parties were allowed to present the parties that the

comment on the update exhibit at the same time they commented on the ALU draft decision in this proceedings that they commented the

b. EOR. NSRA and CPA 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.

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d. NGV Mcmorandum 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 CoreElect Subaccount,

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

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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 Pees - Williamon of the book of the brokers of the book of the brokers of the broke

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

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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.

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5. Discounting

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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 and a second 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 togother fuels than all could be recovered in rates. The City of the same allowable

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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.

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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. SCE Cool Water Revenues

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 so 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. The way we have a common the period of the common terms o

Fixed costs are relatively stable. They tend to be all the independent of the amount of gas flowing through the utility is a second system. The largest fixed cost which must be allocated is the base revenue requirement adopted in the utility's most recent general $\mathbf{r} = (\mathbf{r}, \mathbf{r}_{\mathbf{r}})^{-1} \cdot (\mathbf{r}_{\mathbf{r}}, \mathbf{r}_{\mathbf{r}})^{-1}$ Carlotte and the market of the same 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. (CC) 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 an entire the second charges and the second charges are second charges. 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 analysis 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 the state of the

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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.

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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.</u>

FERC. (D.C. Cir. (1989) 893 F. 2d 349). The FERC did accept the alternate tariff sheets (which are based on the percentages in El

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Paso's pending global settlementpoffer) and suspended them for five months to become effective May 17, 01991 at (53 FERC: ¶61,373,) below to be

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-payotrue 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. Stipulating Parties Position Colon Colo

In their original testimony, both PG&E and DRAShas (1/4) 177 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. The transfer 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 1868 this docket, last year's PG&E ACAP docket and SoCalGas' 1989 - 1990 ACAP proceeding. The Joint Motion argues that in light pofprecented 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 considered deficiency methodology on the grounds that it violated the filed or 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 USSLW: 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 the 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.

Motion as to this application and last year's PG&EnACAP on the November 26, 1990 agreeing to the \$27.5 million in the Stipulation for TOP costs and the stipulation of the Stipulation o

The stipulating parties, particularly PG&E; TURN, hand 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 has should be changed. The update exhibit addresses this issue:

stating: "After consultation with DRA, CIG; and TURN;" PG&Bolive File believes that the original estimate of direct-billed take-or-pay costs of \$27.5 million remains a reasonable estimate of expected to costs." \sim (Exhibit 28, p. 1-1.) Fraction years of all the residence probability

The update exhibit offers no further justification of the stipulating parties for the \$27.5 million figure. Therefore, we do 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 a class earlier testified that she thought TOP costs would be about \$41.3 million to \$43.9 million if the BlaPaso settlement is a set the settlement of 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. Salmon Resources Ltd.'s Position

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 a control of eliminated due to the two orders issued by FERC in December 1990 (and discussed earlier in this decision).

Salmon arques that FERC's December 7, 1990 order (53% and F.E.R.C. 161,348) 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.

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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.

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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 indits comments, allowing us towinfer that discobjection to the 27.5 million figure has diminished. The property of the comments of the

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2- 90% Balancing Account for NonCore Transportation Revenues

o 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 of 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

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resulting from PG4E's next cost allocation proceeding, currently as estimated to be Spring 1992. (Exhibit 27, pp. 7-8.) (The d. The columns of the control o

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

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 accordance review. The experience of the month of Laboration by Ambrot Market

d. Discussion of General and about ancomer, 20 a menomorphic

The Stipulation's:90 percent balancing account treatment seemingly conflicts withwour 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 second as 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. sarguments that we see that 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 notato availathemselves of the book in the opportunity to either offer testimony against the 90 percent figure or cross-examine the panel members as to their reasons for when the 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 coverdo not believe it is a 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 were approach in D.90-09-089 during their settlement negotiations Clearly, the 90 percent treatment was thought to be a better when 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. and the contract of the contra

The stipulation provides that this:90 percent balancing account remain in effect until implementation of rates resulting and 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 equations 90 percent balancing account approved today will sconvert as the same automatically to a 75 percent balancing account on May 15, 1992, ... without further Commission action. The second of the secon

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

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C. Is the Stipulation, as a Whole; in the Public Interest? The Stipulation of 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. The state of the same and the same transfer and the same and the s

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 the second 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 The Telephone stipulation before us today.

IV. Contested Issues Not Addressed By The Stipulation to the stipulation

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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 an account. addressing the appropriate allocation of the Mojave Cogeneration contract revenues. The property of the first of the state of th

1. PG&E's Position whom let be not be not because of the scool and well as

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. ు ఎందుకుండి కార్యం కార్యం కార్యం కార్యం ఉంది. మీ సంచారం కార్యం కార్యం కార్యం కార్యం కార్యం కార్యం కార్యం కార్యం 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 here simpler to implement and is already familiar to the Commission, having been adopted for the treatment of EOR and interutibity transportation revenues. The state of the st

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 becon 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 longterm 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 fitransition cost of for allocation purposes of the new gas industry structure as a fitter of the second structure of the second s

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 and distribution system in a manner beyond the reach of industrial customers.

explicitly treat the revenue shortfall resulting from the lockingin 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.

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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 aspassages in D.87-05-046; that what 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.

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C. Cogeneration Rates | L. L. C. Co. Company of the Company of the

1. Overview

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.

ence of 2. The PG&E's Position of the property of the Construction of the State of

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 SO4 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

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groups who are parties to the case took no position whatsoever on the issue. On the common to the produce confidence and more dead with

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. The second of the secon

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. and the state of t

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 bear 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 SO4 Payment Option 30 - 50 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 the 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. The transfer of

one problem by creating another in altering rate design and methodology.

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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.

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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 consideratement than exists in their respective briefs consthis a disagreement.

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

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ుగారు కుండా కొండుకుండి కార్వారు కొండుకుండి. మండుకుండుకుండి కార్వారు కార్వారు కొండుకుండి కొండుకుండి. మండుకుండి అన్ని కార్వారు కొండుకుండి దివింది. మండుకుండి కొండుకుండి కార్వారు కొండుకుండి తెంది. మండుకుండి కొండుకు మండుకుండి కార్వారు కార్వారు కొండుకుండి కొండుకుండి కొండుకుండి. మండుకుండి కార్వారు కార్వారు కొండుకుండి. మండుకుండ మండుకుండి కొండుకుండి కార్వారు కొండుకుండి. మండుకుండి కొండుకుండి కొండుకుండి కొండుకుండి. మండుకుండి మండుకుండి కొండు 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 is not 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.

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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. CCC's Position providence incommunity and accurate aids bedomented and

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

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had adequately audited the account; and 4) any monies collected and since last year in rates should be credited toward the total and the

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. CRA 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

V. Refund of Core-Elect, Purchased to produce the Gas Account Regional Company of the State o

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Background - Committee of 1977 of the Art Court of the Person of the Annual Control

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 concerned 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.

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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.

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B. Discussion

It is unusual for an issue such as this to catch all the 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 ones. 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 continued appropriateness of a refund under these circumstances and our and appropriateness of a refund under these circumstances and our and appropriateness of a refund under these circumstances and our appropriateness of a refund under these circumstances and our appropriateness of a refund under these circumstances and our appropriateness of a refund under these circumstances and our appropriateness of a refund under these circumstances and our appropriateness of a refund under these circumstances and our appropriateness of a refund under these circumstances and our appropriateness of a refund under these circumstances and our appropriateness of a refund under these circumstances and our appropriateness of a refund under the circumstances and our appropriateness of a refund under the circumstances and our appropriateness of a refund under the circumstances and our appropriateness of a refund under the circumstances and our appropriateness of a refund under the circumstances and our appropriateness of a refund under the circumstances and our appropriateness of a refund under the circumstances and our appropriateness of a refund under the circumstances and our appropriateness of a refund under the circumstances are a refund under the circumstances and our appropriateness of a refund under the circumstances are a refund under the circumstances and our appropriateness of a refund under the circumstances are a refund under the circumstances and our appropriateness of a refund under the circumstances are a refund un 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. The state of the second of

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.

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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 in the definition of applicable proceedings.

Rule 76.54 requires filling 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 consider the be sought; and the sought of the compensation that will consider the consideration that will consider the compensation that will consider the consideration that will consider the consideration that will consider the consideration that will be considered to the consideration that will be considered to the consideration that will be considered to the consideration that we can also the consideration the consideration that we can also the consideration the consideration that we can also the consideration the consideration that we can also the consideration that we can
 - (4) A budget for the customer's presentation. I am when the

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

A. Significant Pinancial Hardship

mean both of the following: The following to the following of the following the follow

- "(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. Statement of Issues who are the world by the commence and an experience

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 second 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).

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)(l). 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. The first of the first of the second of the And the second s

VII. Transcript Corrections

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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: "Grade to

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ార్వి కారార్డ్ అంది. మార్జుకా స్ట్రాల్ ఉద్దేవార్ (గ్రామంలోలో ఉద్దేవార్లు) అంది **చెలుకుండు ప్రా**త్యాత్రి చేసిని ఉద్దేవారి

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- 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.
- examine the stipulating parties on any of the underlying issues.
- element in the ACAP. A second of the second
- 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.

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- 10. DRA recommended adoption of a RAAC of \$29.75 for the ACAP period. w and one product when a war about open one and apply mit and
- 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 2 mid the boundary
- 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 the state of th assumption that oil prices will be high enough so that only minimal discounting will occur, yet recognizing the uncertainty by the continuous states of the continuo incorporating a 90% balancing account for non-core transportation ... revenues. and the second of the second o
- 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. The control was the control of the
- 16. In an ACAP, estimates of the weighted average costbofogas (WACOG) for both the core portfolio and the non-core portfolio are developed. and the first than the second and the larger transfer and the segment
- 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 forecasts (PG&E) and the lowest: (DRA) dis less than 7% at odd ord pour decommon good more are

- .21. Thus the stipulating parties urge that adoption of \$2-230 per Dth for the core WACOG, which is within 4% of each of their (1) original forecasts, is a reasonable approach for the Commission to take. (10.7) In the common to the common terms of the common terms of the common terms of the common terms of the common terms.
- 22. We agree with the stipulating parties that their core and WACOG of \$2:23 per Dth is a reasonable compromise of their original positions. While it is a second to the result with the full looked to a look
- 23. With only a penny per Decatherm in dispute between DRA of and PG&E we see no reason to do anything other than adopt the MARK stipulation figure of \$2.52 per Dth for the noncore WACOG. The last the
- 24. PG&E originally forecasted 16.8 MMDth of G-P2B throughput, 129.1 MMDth of G-IND throughput and 9.1 MMDth of the grant industrial GC-2 throughput: The component was the BUSH of the
- throughput, 169.4 MMDth for G-IND throughput and 9.1 MMDth for GC-2 throughput. and the state of t
- 2610 The stipulating parties compromised on their poriginal: 300 position and agreed on the following forecast: 1705 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 Cook Water was
- 28. TURN's original forecast for Cool Water throughput was - CONTROL OF THE SECOND CONTROL OF THE CONTROL OF T 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 Reportain conjunction with the Cool and Water forecast incorporated into SCE's September 1990 ECAC State of the SCE settlement agreement.

- 31.00 PG&Ecand DRA: fundamentally agreed contitle, cogeneration of the throughput forecast, despite the fact that PG&E had forecastwall was slight amount of curtailment to these customers indits original filing: A to the second of the
- 32. The stipulation's cogeneration forecast, which we have 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 formany 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 College College 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. We have the control of t
- 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. More than all out of the second
- 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 angle of the stipulation. A second of a community of the second of the The section of the control of the

40. There was no dispute among any parties in their original testimony as to PG&E's original forecast of 13.70 MMDth for the month wholesale throughput.

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- 41. By adopting the above noncore throughput numbers as set of 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 your direct 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 gasthe second of the second of the second of the second 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. The wild 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 dead prepared testimony. 13000 C 15000
- 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. We will be referred to the controversial 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 on the 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 the 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 CoreElect 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 feescredit 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.

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- 79. The stipulation recommends that the Commission adopt the cost allocation methods set forth in PG&E's prepared testimony are except as expressly noted in the stipulation. (Exhibit 70)
- 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 dissues arose with regard to core rate design: the level of residential Tier differential reduction and the calculation of the LIRA: (Lowell 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 cone to reduce the residential tier differential because it reflects the consensus of the parties.
- 84. PG&E recommended as 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 and Kee estimated TOP costs of around \$50 million. A CONTRACT OF THE PROPERTY OF
- 90. The Stipulating parties propose a \$27.5 million forecast of TOP costs to be incurred by PG&E during the test period: Section 1986
- 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 Construction of the second of the contract of 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. Who have a first two two class we have the
- 93. Salmon arques that the forecast should be at cornear and the S50.3 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. The second of the second is a conditional to the
- 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 4 now based primarily upon the "timing" of FERC action on the El Pasorate case settlement. The substitute of the value of the property of the case of the case
- 95. While our inclination is to support the stipulation and the number reached by a diverse group of parties, we are troubled by the arguments raised by Salmon respect to the control of the control of the
- 96. The parties have convinced us in their comments to the parties proposed decision that the \$27.5 million forecast is reasonable in light of FERC's approval of the El Paso Settlement. In any is improved
- 97. The stipulation specifically calls for 90 percent of any variation between noncore transportation revenues, excluding those was revenues amortizing balances in existing balancing accounts, mander the adopted noncore revenue requirement, excluding balances of

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existing balancing accounts; beoplaced 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 is 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).

- 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.
- 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.
- 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 where we will only bedaddressing of the appropriate allocation of the Mojave Cogeneration contract where revenues.

- 111. PG&E proposes to treatorevenues 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 and EOR contract. DRA argues that long-term, non-EOR contracts should be a treated as revenue shortfalls.
- 113. However, both DRA and PG&E agree that whether itsis and all credit or shortfall, it should be recovered from all other 1000 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 demands 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 to be indifferent as to whether those revenues are treated as shortfalls or credits.
- 117.4. We agree with DRA, PG&E, and CIG et al. that revenue to allocation on an equal cents per therm basis for the Mojave, the loss of the distance of the mojave of the distance of the dist

Cogeneration contract is the most appropriate and consistent with D.87-05-0464 The Mojave Contract is not an EOR contract to a revenue of

11820 As to the debate between PG&E and DRA over theorevenue and credit vs. shortfall issue, we find this argument to be "much adoms 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 agree of the context of the conte

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 recordain 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 conforcasted rates because it had not been developed in testimony.

PG&E to discontinue entries to the CSA account. We also deferred recovery of the existing balance until this proceeding incorder to allow for a detailed audit of the transactions in the account.

- 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 of the 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 them was a second 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.
- effective date of its revised tariff schedules to implement them a refund.
- 133. TURN's request for eligibility was timely filed and addresses all four elements required by Rule 76.54 (a) mofathe at 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.

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- 135. GIURN has demonstrated that sits sparticipation in this proceeding swould pose a significant financial hardship under species Rule 76.52(f) and Rule 76.54(a)(1). The second of the concept 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 metaby allowing all parties an opportunity for adequate crossexamination 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.

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- 10. We should adopt a forecast of \$146.3 MMDth for UEG . 3.3 throughput, which assumes \$18.2 MMDth of curtailment because sit was agreed to in the stipulation.
- 11. We should adopt the stipulation curtailment level of the stipulation curtailment level of the stipulation curtailment level of the stipulation.
- 12. We should adopt PG&E's original forecast of 13.7 MMDth of wholesale throughput because no party disputed the figure 2. 2000 to 1000 to 100
- 13. We should adopt a residential throughput forecast of 217.2 MMDth and a commercial throughput forecast 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 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.
- agreed to in the stipulation.
- 30. We should adopt the stipulated cost allocation as settled forth in Exhibit 27 (Appendix D) in a last set allocation as settled.
- 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 burdens 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.

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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.

1 CERTIFY THAT THIS DECISION WAS APPROVED BY THE ASOVE COMMISSIONERS TODAY

AN. Exocutive Director

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

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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 <u>Barbara Barkovich</u>, for Barkovich & Yap; <u>Patrick J. Bittner</u>, Attorney at Law, for California Energy <u>Commission</u>; <u>Jerry R. Bloom</u>, Lynn M. Haug, and Morrison & <u>Foerster</u>, 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: <u>John S. Wong</u>, Attorney at Law, Larry Klapow, and Natalie Walsh.

873,605

TABLE 1

PACIFIC GAS AND ELECTRIC COMPANY ADOPTED GAS DEMAND

Forecast Period: April 1, 1991	to March 31, 1992
THROUGHPUT TYPE	୍ୟGAS ∵DEMAND (Mdth)∙
و مولا کا ادامه از این در این بن ساور بین نی مرابع کا انتخاص این در این در این این این در این این در این این در	
Residential Commercial Core Industrial (incl. GC2) Steam Heat UEG-PG&E (incl. start-up) UEG-Edison Cogeneration (excl. GC2) Cogeneration EOR Cogeneration EOR Steaming Company Use Unaccounted For Wholesale Interdepartmental Interutility	217,243 90,639 164,900 1,086 -165,883 23,900 6,600 -28,447 22,138 8,174 17,543 13,738 314 50,000
Interactive	7.5.7 00

TOTAL GAS DEMAND

TABLE 2

PACIFIC GAS AND ELECTRIC COMPANY ADOPTED DEMAND FORECAST BY PRIORITY

PRIORITY	DEMAND FORECAST (Mdth)

P-1	333,448 _{61,668}
P-2A	14,625mm
P-2B	00-5365
P-3A	100 . 152. 15 4.9 87.047 10900
P-3B	იის ქალიციადე გაგათა 68,,785 ა სელ
P-4	**************************************
P -5	120% Ly Javonsaff 241,356, 150%
A Company of the Comp	ing munity og nøben ob 1 A <mark>ttalled i 1</mark> 70 to 1
TOTAL	873,605
	makatarata ingapa jikanpun

. Z_{kj} 4

TABLE 3A PACIFIC GAS AND ELECTRIC COMPANY ADOPTED DEMAND, CURTAILMENTS AND SUPPLY FORECAST BY CUSTOMER CLASS

SCHEDULE AND CATEGORY	PRIORITY	V - 2.00	DEMAND FORECAST (MDTH)	CL	irtail+ Ments (MDTH)	SUPPLY FORECAST (MDTH)
nervoorgen perene mande mande en RESIDENTIAL	P-1	#20E##177	217,243	1560E2#-	0	217,243
		400			٥	72,973
COMMERCIAL GT-NRT	P-1	1.4	72,973 6,070	1.5	Ď.	6,070
COMMERCIAL G-NR2C	P-1		79		ŏ	179
COMMERCIAL G-NR3N	P-1		74		ŏ	74
COMMERCIAL G-NR3T	P+1		2.257		ā	2,257,
COMMERCIAL G-NR1	. P+2A P-2A	1,500	9,105		ŏ	9,105,10
COMMERCIAL G-NR2C	P-2A		29		ŏ	29
COMMERCIAL G-NR3N	P-2A		112	. **	ă	112
COMMERCIAL G-NR3T	P-2A					
1997, 5 T		1 10 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1		• • •	0	90,639
TOTAL COMMERCIAL	,		,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,			
republic	P-2B	11,860	12,251		٥	12,251
INDUSTRIAL G-P28C			3,393		ō.	3,393
INDUSTRIAL G-P2BN	P-28		1,856	1 4		* '' a add (****)
INDUSTRIAL G-P2BT.	P-28	-Y"	1,000			7 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
in the state of th			17,500		0.	17:500-^
TOTAL P28			17,500			or it
	0.70		19,067	A . •	0	19,067 45
INDUSTRIAL G-INDC	P-38		9,261		o,	0.261
INDUSTRIAL G-INDN	P-30	11. N	17,311	17.4	0	17.311
INDUSTRIAL G-INOT	P-3B	A	1,201	4.1	6;'	1.201
INDUSTRIAL GC2-C	P-38	• ' '	577	, P.,	0.7	577
INDUSTRIAL CCZ-N	P-38	S To a	1,225		ŏ	1,225
INDUSTRIAL GC2-T	P-38	1000	38,712		ă	38,712
INDUSTRIAL G-INDC	P+4		18,503		. 0	
INDUSTRIAL G-INDN	P-4	•			ň	A. A. M. 25, 146
INDUSTRIAL G-INDT	P-4	5.75 M	35,146 2,439	1) j	2.439
INDUSTRIAL GC2-C	p-4		1,171		Ď.	بهر ا171 و 1 بدر م در در
INDUSTRIAL GC2-N	p-4	31	2,487		0	14. C. C. 2,487
INDUSTRIAL GC2-T	P-4		2,407			******
1 North		C_{i}	-/7 /00		0	147,400
TOTAL G-IND & INDUSTRIA	AL GCZ		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		٥	19,238
COGENERATION GC2-C	P-3A		3,300		٥	3,300
COGENERATION GCZ-N	P-3A		1,293		0	1,293
	P-3A		2,007		0	2,007
COGENERATION GCZ-T	, 54			•		
TOTAL COGENERATION			69,600		0	69,600
						8,534
EOR COGENERATION C	P-3A		8,534		0	1,707
EOR COGENERATION N	P-3A		1,707		0	18,206
EOR COGENERATION T	P-3A		18,206		U	10,200
COD CTEAMING C	P+5		0		¢	0
EOR STEAMING C	P-5		2,214		182	2,032
EOR STEAMING N	P=5		19,924		1,633	18,291
EOR STEAMING T	F-3		******	-		
			50,585		1,815	48,770
TOTAL EOR			34,303			•

TABLE 38

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

SCHEDULE AND CATEGORY	PRIORITY	DEMAND- FORECAST (MOTH)	MENTS (MDTH)	FORECAST
STEAM HEAT G-NCT	P-4	1,086	· · · · · · · · · · · · · · · · · · ·	1,086-
UEG-PGEE	P+5	164,438	18,178	146,260
UEG-PGEE START-UP	P-2A	1,445		1,445
UEG-SCE G-NCT	P-38	19,120	0	19,120
UEG-SCE G-NCT	P-5	4,780		4,780 ₄₆
TOTAL UEG	` .,`	189,783	18,178	
MISC COMPANY USE	P=1	8,174	0	8,174 ve
UNACCOUNTED FOR	P-1	17,543	O	17,543
•	2.5 💉		EMEROGERA	
TOTAL RETAIL		809,553	19,993	772,060
COALINGA G-WRT	P-1	170		.000 at 170 a
CP NATIONAL G-WRT	P=1	76		76
PALO ALTO G-WRT	P-1	2,722		2,722
SOUTHWEST G-WRT	P-1	8,173		8,173 m 33
COALINGA G-WRT	P-2A P-2A	33 671		33 11 A. B. 7.3671 (2.1
PALO ALTO G-WRT	P=2A	973		2.70 0.70 0.70 0.70 0.70 0.70 0.70 0.70
PALO ALTO G-WRT	P-38	336		336 a
SOUTHWEST G-WRT	P-38	584	•	0.004 Jan. 9 584 69
TOTAL WHOLESALE	1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1	13,738		19-1/07 1-100
INTERDEPARTMENTAL C	P=1	211		- 00 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
INTERDEPARTMENTAL C	P-38	103		1347 L 343 103(a)
**	\	*******		**
TOTAL INTERDEPARTMENTA	L	314		- ж. т.ш. — да ду 314 ду ^ў - 172 ў — да ду 37 00джі
INTERUTILITY	· · · · · · · · · · · · · · · · · · ·	50,000		50,000
14164012211	The state of	30,000	P. H. A. C. S. C. S. C. S.	raci v. Srimi sasti,
TOTAL	Service and	873,605	46 19,993	და. აუ გუგ_ა112 ეე
	المأراف ا			Made action of man
				Der 201145 (4500)
•	2 ³⁰ 4			COL ROTTING SPOND
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4.45			1964	COC: MERKETORY COC
Ç.O	20,000		,	יים אני ממערטטי איז בי
	2.1.		Albert S	WILDAM, POSOS SOS
	5.75.7		AC# 1	POSTAKOK MOSE POS
i e i gir	67.36		AC+11	NOT LUNY NY NY DOG - SOG
•	ડે		2 - 57	CONTRACTO SON
	** * * * * * * * * * * * * * * * * * *		1.4	V GREMAZIO NOS
Section 1	26.50		Sar.	SON UTCOME AND
Age ◆	राज्यालय			หมิด แ ละเ ตะ

9210-401-00 A

TABLE 4

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__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
			▼	e e e e e e e e e e e e e e e e e e e	i supra serve di la considera Serve di Companya di Serve
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			(Sens	22,162
CORE-ELECT PGA REVENUE (3)		0		neady, 0	115 Sec. 30
SUBTOTAL REVENUE	711,508	668, 133	73,211	30,638	1,483,490
F&U RATE [4]	0.00899	0.00899	0.00899	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1	0.00899
,				i di kacamatan da matu. Kabupatèn kacamatan da matu kacamatan kacamatan kacamatan kacamatan kacamatan kacamatan kacamatan kacamatan ka	erra alterna a a a a a. 1997 i Connecentoria
F&U	6,396	6,007	658	7.44 (Z17)	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 / ₄	
		********	*********		44 700
BROKERAGE FEES		10,242	993	470	
BROKERAGE FEE FAU		92	Y		gr. gr.n 104 -
BROKERAGE-FEES INC F&U	-	10,334	1,002	473	11,809
BROKERAGE FEE RATE (b)		0.00345	0.00345		
	*******	*********	*********	i i Managaranan (
FINAL PROCUREMENT RATE (4+5)	0.23224	0.22845	0.25772	0.22803	લકાલિક જ મહાસ્થાન

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^[1] RATES MAY VARY DURING THE TEST PERIOD.

⁽²⁾ SALES VOLUMES REFLECT SHRINKAGE AND STORAGE.

TO SUPPLEMENTATION OF THE SUPPLEMENT OF THE SUPP CST ACCOUNT BALANCE IS \$46,694. CUSTOMERS WILL BE REFUNDED PER THIS DECISION 2000 - 20 - 200 - 2

^[4] WHOLESAUE PAYS FRANCHISE FEES ONLY.

P70-00-00-0

TABLE 5

PACIFIC GAS AND ELECTRIC COMPANY ADOPTED REVENUE REQUIREMENTS

PROCUREMENT REVENUE REQ	UIREMENT	King Stranger	· · · · · · (\$00	0/ s }	
rotal Core Procur. Reve rotal Non-core Procurem rotal Wholesale Procure	nue (incl Core	-elect)	art a tal	,346,996 73,869 28,793	•
Prokerage Fees Cincl. F	ZU)	1. 1. 1. 1. 1. 1. 1. 1.	****************** *	11,809	on and the contribution of the
TOTAL PROCUREMENT R	EVENUE REQUIRE	MENT "TOTAL	16, 16, 1		::::1 ;461;,468 ;::::::::::::::::::::::::::::::::::::
RANSPORTATION REVENUE	REQUIREMENT	e e e e e e e e e e e e e e e e e e e			i da tukivar varonska
			1. A. F		200 AV (4. AC2. 1940
luth. gas mergin		4		276,945	LEUW DVIN AUG HOUDS-1985
Common distribution Demand related transm	niscion			212,600	THE PROPERTY OF THE PROPERTY O
Demand related storag					
		1.07 (23%)	Contract Contract	499,381	SCHOOLS NATIONS
Commodity related	$\sqrt{N}^{(i,j)} = \sqrt{2}$	3377.65	ogradio j	10,145	Ag 35A 15.
50% Adminstrative & C	eneral	9 Y 1		88,634	
Franchise & Uncollect	ribles	er også	4.8	10,208	
Less: Brokerage Fee	15			(11,810)	
'Less: 'Other operati	ing revenue	· • - · · · · •		(9,149)	
Less: Long term cor	JELBEZ "LANGUNG .	Out Lines	25.9 85.11 25.5 1	(2,030	מניעטאטנ .
			-		1,117,964
	i lego,	460) (1 <u>.</u> 4	A control process	176 496	s Canagan iyotin iya
Pipeline demand-charges		titatu yayata	t a willes of	1,580	 Suppose the Superful Super
Add: FEU at 0.00895		*******	-1		
327,53		S. S. C. L. F.			178,,076 3A41599
Transition costs	Ņ.	' 1		27,500	JUN 100 100840304
Add: FEU. at 0.00893	•			245	
N. 10 10 10 10 10 10 10 10 10 10 10 10 10			•	• • • • • • • • • • • • • • • • • • • •	
-	10.0	to the second			- 0 1 50. 27,745 2/уа0чоя
EOR' / Interutility Rev	enue Credit	1 m 4 2 m		1,080	THE PARTY (19,080) ARTHORN
DSM and RD&D Revenue Of	ffset	4 + 4 4 4 4		20,467	
EL PARO TOP Trueup	are con-	1 1 1 1	7378.5	3:002	PRANTALIN PURCORT LAND
HALLMAN A STANDARD AND STANDARD				14,574	
Gas Storage Carrying Co				49,873	
Gas Fixed Cost Account				(13,798	
Non-core Balancing/Trac Core Company use and u	exing Accounts	CAS		26,252	
	naccounted for	FOR OAK		35,589	
Lore company one and a	IN BURCHARIERA	(U. 905		2,628	
Non-core Company use at	YDODEO			60 000	
Non-core Company use at CFA Debt Service and E	XPense	int		50,000	
Non-core Company use as CFA Debt Service and Ex Gas Exploration and De	XPense		Proceeding.	4,489	THE PROPERTY OF STREET OF
Non-core Company use at CFA Debt Service and E: Gas Exploration and Det CPUC Fee	xpense velopment Accou ance	الإراف بي ن	100 000 000	4,489	Milit Mark Kamadattab (1 toota (1860) Nobelaar Kt
Non-core Company use at CFA Debt Service and E: Gas Exploration and Det CPUC Fee Low Income Rate Assist	xpense velopment Accou ance	الإراف بي ن	100 000 000	4,489	rruud Provinsi kaak idoogaa jiri Konsta Seedaa Willia aasti kro
Non-core Company use at	xpense velopment Accou ance	الإراف بي ن	in okkunda Lokuski Nija	4,489 1,961 1,759	1, katol mak kasel bust 21 dayan Maddmir an it 31 apg <mark>olmi da</mark> ykadi se
Non-core Company use at CFA Debt Service and El Gas Exploration and Der CPUC Fee Low Income Rate Assist Add: F&U at 0.00897	xpense velopment Accou ance	, p. ka ONE HOBERT DE BUM	in okkunda Lokuski Nija	4,489 1,961 1,759	HILL TORUM HAR LOTAN (C.) TORIA HUROUMY LUMAD IN BUS BRANAD TYKOOQA (B) MAN KYAN OO?7,966,6 844 (A.)
Non-core Company use at CFA Debt Service and E: Gas Exploration and Det CPUC Fee	xpense velopment Accou ance	, p. ka ONE HOBERT DE BUM	in okkunda Lokuski Nija	4,489 1,961 1,759	1, katol mak kasel bust 21 dayan Maddmir an it 31 apg <mark>olmi da</mark> ykadi se

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

(193)

486

(289)

3,092

3,585

1,851,209

(1,021)

Gas Storage Trueup

F&U

TOTAL COSTS

Noncore Base Cost Adjustment

Earthquake Recovery Adjustment

California Corporate Franchise Tax Adjustment

1990 ACAP FEU Adjustment

TABLE 6 PACIFIC GAS AND ELECTRIC COMPANY ADOPTED COSTS

ForecastedForecasted Period: April 1, 1991 to March 31, 1992 COSTS PRICE VOLUMES (\$/th) -----(\$000/s)----(Mth) Gas Supplies 1,388,117 6,224,740 290,520 0.22300 Core & Core-Elect 1,461,328 14,574 11,705 0.25200 73,211 Noncore Gas Storage Carrying Cost Brokerage Fee Pipeline Demand Charges 92,081 PCT-Canadian 42,012 PGT COST of Service 176,496 EL Paso Transition Costs 27,500 El Paso Take or Pay 77,500 50,000 GEDA CFA Debt Service 2,628 2,238 Expense Gas Dept Use & Unaccounted for 7,250-15,556 12,406 0.22300 Gas Department Use (Core) 32,510 22,806 0.22300 69,760 49,230 Unaccounted for (Core) 0.25200 Gas Department Use (Noncore) 26,629 39,035 0.25200 105,670 Unaccounted for (Noncore) 4,489 1,961 CPUC Fee LIRA A&G Balancing/Tracking Accounts 22,162 Core Purchased Gas Account (46,694) 49,873 Core-elect Purchased Gas Account Gas Fixed Cost Account Noncore Accounts (2,492) Enhanced Oil Recovery Account (109) ALS Interutilist Delancing Account (1,671) CFA Debt Service 344 CFA Expense (2,699) Noncore Transition Cost Account 1,106 Cogeneration Shortfall Account (13,798) (8,277) LIRA Account 20,467 EL Paso TOP Trueup Noncore Adjustments 2,401 1,708 Pipeline Demand Trueup

(END OF APPENDIX B)

TABLE 1

PACIFIC GAS AND ELECTRIC COMPANY SHARP STORES OF MAKE STORES OF MA ADJUSTED ALLOCATION FACTORS BY CUSTOMER CLASS

				, 40000	O MCCOCA!	100 1001	M3-01 403	I THE		.h.		96	据。 特别来。
				Forecast	Period:	April 1,	1991 to 1	larch 31,	1992	ç	19 (19 (19 (19 (19 (19 (19 (19 (19 (19 (प्राचित्र स्ट्रीटिस्ट्र
*****	2 2 5 3 3 5 6 7 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1							11	******		,		reservate '
	•••		SM COML	G-NR1	G-NGV	G-NCV	LG COML		PZB NC	IND	UEG	COGEN	WHOLESALE"
ALLOCAT		RESIDENTIAL		WINTER		UINTER	SUMMER	WINTER	G-P28				
INDEX	ALLOCATION FACTOR			WINIEK Berrrandski	JOHNER	MEREKEN MEREKEN	,,,,,,,,				.,422,000,000	****	
	D-COST OF SERVICE *				,			1,	, -	. (.)			raa Bibiliyaha
8	Avg. Yr. Throughput	0.30638	0.10834	0.00000	0.00000	0.00000	0.02207	0.00000	0.02401	0.22063			_0.01941 [©] _
ь	Weighted Customers	0.90179	0.07613	0.00000	0.00000	0.00000	0.00202	0.00000	0.00125	. 0.01290			0.00043
č	Pk. Seas. Cold Yr. Thrpt.	0.42577	0.12324	0.00000	0.00000	0.00000		0.00000	50.02007				0.02396
ď	Cold Yr NC Pk Mo Dist Thrpt	0.64018	0.17262	0.00000	0.00000	0.00000		0.00000					0.00000
ė	Cold Yr. Throughput	0.33861	0.11452	0.00000	0.00000	0.00000	0.02338	0.00000	0.02315				0.01984
Ť	Base Revenues	0.66175	0.11168	0.00000	0.00000	0.00000		0.00000	0.01183	0.09983	0.05709		0.00582
o o	Revenues less Wholesale	0.66563	0.11233	0.00000		0.00000	0.01700	0.00000	0.01190				0.00000
ĥ	Rev. plus Pipeline Dmd. Chg.	0.61819	0.11206	0.00000	0.00000	0.00000			0.01336				0.00771
í	Avg Yr. Thrpt. Less Shrnkg.	0.30638	0.10834	0.00000	0,00000	0.00000	0.02207		0.02401	0.22063	0.20667		0.01941
j	Avg Yr. Thrpt NC	0.0000	0.00000	0.00000	0.00000	0.00000		0.00000	0.04263	0.39173	0.36694	0.16423	0.00000
k	Customers, Core	0.92025	0.07769	0.00000	0.00000	0.00000	0.00206	0.00000	0.00000		0.12309		0.02134
l	Customera, NC & Whal	0.0000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.06236		0.20858	0.14976	
m	AEG Allocation **	0.30922	0.10935	0.00000	0.00000	0.00000	0.02228	0.00000	0.02423	0.22268 0.72809	0.00000	0.16313	
n	CYNC PK, NC	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.10076	0.72009	0.00000	0.10313	0.00000
	NG ACCOUNTS AND FORECASTED PERIOD COSTS	. Ara A34	0	, 0	· 6	. 0.	•	0.	0.	٥		0	er a com
	Non-LIRA Requirements	2,050,021	•		.0.	. 0.	å				1 515 748		142,383
	Adjusted Deliveries (Incl. Shrinkage)	2,247,060	707 #20	794,612 458,930	234	317	62,290	93.871	175 160	1 725 550	1 462 600	605 570	137,390
. '	Unadjusted Deliveries:	2,172,460 0,30638	307,820		0.00000	0.00000		0.02207	0.02401	0.22063	0.20667	0.09250	0.01941
1	Cts/Therm - All: Cts/Therm - No Gog, UEG, Whl:	0.44961	0.00000	0.15899	0.00000	0.00000	0.00000	0.03239	0.03523	,			0.00000
Ž Ž	Cts/Therm - No Cog, Dia, Will:	0.70143		0.24804	0.00000	0.00000			0.00000				0.00000
7	Cts/Therm - No Whisi:	0.31244	0.00000	0-11049	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			0.00754
6	Cold-year Deliveries:	0.33861	0.00000	0.11452	0.00000	0.00000	0.00000	0.02338	0.02315				0.01984
7	Peak-season, cold-yr Deliveries:	0.42577	0.00000	0.12324	0.00000	0.00000	0.00000	0.02531	0.02007				0.02396
8	Cts/Therm - No GC-2:	0.31332	0.00000	0.11080	0.00000	0.00000	0.00000	0.02257	0.02455	0.21245			0.01985
9	Cts/Therm - Noncore Only:	0.0000	0.00000	0.00000	0.00000	0,00000	0.00000	0.00000	0.04263			0.16423	
10	Cts/Therm - Noncore Except Whis:	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000			0.38004	0.17009	
11	Cts/Therm - All - Shrinkage:	0.29792	0.04221	0.06293	0.00003	0.00004	0.00854	0.01287	0.02402	0.23663			0.01884 [©] 0.00000
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	
13	Cts/Therm - UEG and Cogen Only:	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.03668			0.00000	
14	Cts/Therm - No LIRA, UEG, COG, Whl:	0.42702	0.00000	0.16552	0.00000	0.00000	0.00000		0.07121	0.65443	0.00000	0.27436	
15	Cts/Therm - No Core, COG, Whl:	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000		0.04422	0.40680	0.34070	0.17038	
16	Index 6, Noncore only:	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.04716	0.46536	0.26073	0.17046	
17	Index 7, Noncore only: 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	
18 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	
20	Pct./Yot. 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	
21	Index 18, NC only:	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000		0.05710	0.48004	0.26810	0.16743	
-	Company to a many or m						-					- •	

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

COLUMN COMPANIES CONTRACTOR CONTRACTOR

BY THE REAL OF PROSE OF THE PARTY.

a small or mile oromote

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TABLE 2 PACIFIC GAS AND ELECTRIC COMPANY CONTRACTOR UNADJUSTED ALLOCATION FACTORS BY CUSTOMER CLASS

Company Comp	•	, ,	* 1	· .	ONVOJOZIO	D ALLOCA	TON PAGE	JK3 DI CU.	STOMER GLA	199		1.047,53	W. W. D.	0100000
ALICCATION ALICCATION FACTOR RESIDENTIAL SUMBER UNITER U			•										67770	01000004
ALLOCATION IMPER ALLOCATION FACTOR RESIDENTIAL SUMMER VINTER GP28 G-NCT G-06G M-06G G-NCC	**************************************	B. 数据是共享制度的基本的 19 10 10 10 10 10 10 10 10 10 10 10 10 10	***********		*******			********			(- 144 154 154 15			Henry Mark
EMBEDDE COST OF SERVICE					a 404	#_W#\#	A-UAU							
EMBEDDED COST OF SERVICE			04618544141											
EMBEDDED COST OF SERVICE " A VAY Y Throughput 0.2987 0.10572 0.00000 0.0000					MINIER	DUMER	WINIER		-					
Avg. Yr. Throughput 0,2987 0,10572 0,00000 0,00000 0,00000 0,02545 0,00000 0,0223 0,02373 0,00001 0														0.340555
Description		·	0.29897	0-10572	0.00000	0.00000	0.00000	0.02154	0.00000	0.02415	0.23793	0-20167	0.09108	0.01894
Cold Yr. Ryk Mo Dist Thrpt Cold Yr. Ryk Yr. Ryk Mo Dist Thrpt Cold Yr. Ryk Mo Dist Thrpt Cold Yr. Ryk Yr. Ryk Yr. Ryk Mo Dist Thrpt Cold Yr. Ryk Yr. R	- -													0.00043
d Cold Yr. Prophylput							0,00000		0.00000	0.02023	0.21497	0,10847	0.07160	0.02342
e Cold Yr. Throughput			0.63199	0.17041	0.00000	0.00000	0.00000	0.03505		0.01679	0.12111	0.00000	. 0.02464	0.00000
Revenue's Less Wholesate	e Cold Yr. 1	Throughput	0.33071	0.11185	0.00000	0.00000	0.00000	0.02284	0.00000	0.02331	0.22983	0_17418		
Rev_Plus Pipeline bmd Chg. 0.54321 0.11050 0.00000 0.00000 0.00000 0.00000 0.01548 0.1222 0.07173 0.04188 0.	f Base Rever	nues	0.65723	0.11029	0.00000	0.00000	0.00000	0.01662						
Avg Yr. Thrpt. leas Shrikg. 0.2997 0.10572 0.00000 0.000	g Revenues l	less Wholesale	0,66099	0.11092	0.00000	0.00000	0.00000	0.01671	0.00000	0.01202				
J. Avg Tr. Thrpt NC 0.00000	h Rev. plus	Pipeline Dmd. Chg.												
K Customers, Core 0.02025 0.07769 0.00000 0.	f Avg Yr. Th	orpt. less Shrokg.												
Customers, NC & What 0.00000 0														0.03302
## A&G Atlocation **														
## ACCOUNTS AND FORECASTED PERIOD COSTS **Non-LRA Requirements** **N	l Customers,	, NC & What												
## BALANCING ACCOUNTS AND FORECASTED PERIOD COSTS Non-LIRA Requirements														
Non-LIRA Requirements 2,050,021 0 0 0 0 0 0 0 0 0	n CYNC Pk, N	IC		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.10332	0.74511	0.00000	0.15157	0.00000
Adjusted Deliveries (Incl. Shrinkage) Unadjusted Deliveries: 2,172,660 2,772,660 2,772,660 2,772,660 2,772,660 2,772,660 2,772,660 2,772,660 2,772,660 2,772,660 2,772,660 2,772,660 2,772,660 2,772,660 2,772,660 2,772,660 2,772,660 2,772,660 2,772,660 2,772,770,772 2,772,772 2,772,772 2,772,772 2,772,77			2 050 024						^			· .	1 97 17 6	rdaee
Unadjusted Deliveries: 2,172,460				-	· .	•					•			
1 Cts/Therm - All:						•								
2 Cts/Therm - No Cog, UEG, Whi: 0.43335 0.00000 0.15324 0.00000 0.00000 0.00000 0.03122 0.03501 0.34719 0.00000 0.0000														
3 Cts/Therm - Core Only: 0.70143 0.00000 0.24480 0.00000 0.00000 0.05553 0.00000 0.000	· · · · · · · · · · · · · · · · · ·	· · · · ·												
4 Cts/Therm - No Whisi: 5 Percent/Embedded Cost + pipe d: 6 Cold-year Deliveries: 7 Peak-season, cold-yr Deliveries: 8 Cts/Therm - No GC-2: 9 Cts/Therm - Noncore Only: 10 Cts/Therm - Noncore Except Whis: 11 Cts/Therm - All - Shrinkage: 12 Cts/Therm - All - CPUC Fee: 13 Cts/Therm - All - CPUC Fee: 14 Cts/Therm - No LIRA, UEG, COG, Whit: 15 Cts/Therm - No Core, COG, Whit: 16 Index 6, Noncore only: 17 Index 7, Noncore only: 18 Percent/Embedded Cost: 19 Percent/Embedded Cost: 19 Percent/Embedded Costs: 10 Coold yr Deliveries: 10 Coo														
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 0.6 Cold-year Deliveries: 0.33861 0.00000 0.11452 0.00000 0.00000 0.00000 0.02338 0.02315 0.02195 0.17835 0.08919 0.7 Peak-season, cold-yr Deliveries: 0.42577 0.00000 0.10787 0.00000 0.00000 0.00000 0.02531 0.02007 0.1809 0.11099 0.07256 0.05070 0.00000 0.00000 0.00000 0.00000 0.02531 0.02007 0.1809 0.11099 0.07256 0.05077 0.00000 0.00000 0.00000 0.00000 0.02531 0.02007 0.1809 0.01099 0.02577 0.08378 0.00000 0.00000 0.00000 0.00000 0.00000 0.02531 0.02007 0.1809 0.01099 0.02577 0.08378 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.02531 0.02007 0.1809 0.01097 0.00378 0.00000 0.														
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. 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. 8 Cts/Therm - No GC-2: 0.30505 0.00000 0.10787 0.00000 0.00000 0.00000 0.02315 0.02464 0.23157 0.20277 0.18878 0. 9 Cts/Therm - Noncore Only: 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.04340 0.45054 0.15843 0. 10 Cts/Therm - Noncore Except Whis: 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.04497 0.4624 0.35045 0.15843 0. 11 Cts/Therm - All - Shrinkage: 0.29685 0.04206 0.06271 0.00003 0.00000 0.00000 0.00000 0.04340 0.43041 0.36237 0.16382 0. 12 Cts/Therm - All - CPUC Fee: 0.39680 0.05516 0.08224 0.00004 0.00006 0.01122 0.01691 0.00000 0.35923 0.00000 0.12833 0. 13 Cts/Therm - No LIRA,UEG,COG,Whi: 0.41096 0.00000 0.05516 0.08224 0.00004 0.00000 0.0000	•													
7 Peak-meason, cold-yr Deliveries: 0.42577 0.00000 0.12324 0.00000 0.00000 0.00000 0.02531 0.02007 0.19809 0.17099 0.07256 0. 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. 9 Cts/Therm - Noncore Only: 0.00000														
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_2 0_20577 0_08378 0_2 0_20577 0_08378 0_2 0_20577 0_08378 0_2 0_20577 0_08378 0_2 0_20577 0_08378 0_2 0_20577 0_208378 0_208														
9 Cts/Therm - Noncore Only: 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.04197 0.41624 0.35045 0.15843 0. 10 Cts/Therm - Noncore Except Whis: 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.04340 0.43041 0.36237 0.16382 0. 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. 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. 13 Cts/Therm - UEG and Cogen Only: 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 0.19786 0.09601 0. 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. 13 Cts/Therm - UEG and Cogen Only: 0.00000 0.00				0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0_04197				
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. 13 Cts/Therm - UEG and Cogen Only: 0.000000	10 Cts/Therm	- Noncore Except Whis:	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0_00000	0.04340	0.43041	0.36237	0.16382	0.00000
13 Cts/Therm - UEG and Cogen Only: 0.000000	11 Cts/Therm	- All - Shrinkage:							0.01283					
14 Cts/Therm - No LIRA,UEG.COG.Whi: 0.41096 0.00000 0.15929 0.00000 0.00000 0.00000 0.03245 0.03639 0.36090 0.00000 0.00000 0.56030 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.25633 0.000000	12 Cts/Therm	- All - CPUC Fee:		0.05516										0.00000
15 Cts/Therm - No Core, COG, Whl: 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.06806 0.67501 0.00000 0.25693 0. 16 Index 6, Noncore only: 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.04422 0.40680 0.34070 0.17038 0. 17 Index 7, Noncore only: 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.04716 0.46536 0.26073 0.17046 0. 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. 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. 20 Pct./Tot. Fixed Costs, NC Only 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.05223 0.44510 0.30669 0.16428 0.														0.00000
16 Index 6, Noncore only: 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.04422 0.40680 0.34070 0.17038 0. 17 Index 7, Noncore only: 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.04716 0.46536 0.26073 0.17046 0. 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. 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. 20 Pct_/Tot. Fixed Costs, NC Only 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.05223 0.44510 0.30669 0.16428 0.														0.00000
17 Index 7, Noncore only: 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.04716 0.46536 0.26073 0.17046 0. 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. 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. 20 Pct_/Tot. Fixed Costs, NC Only 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.05223 0.44510 0.30669 0.16428 0.														
18 Percent/Embedded Cost: 0.66696 0.11241 0.00000 0.00000 0.01700 0.00000 0.01163 0.09775 0.05459 0.03409 0. 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. 20 Pct_/Tot. Fixed Costs, NC Only 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.05223 0.44510 0.30669 0.16428 0.														0.03790
19 Index 7, CORE only: 0.74135 0.00000 0.21458 0.00000 0.00000 0.04406 0.000000		•												
20 PCT./Tot. Fixed Costs, NC Only 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.05223 0.44510 0.30669 0.16428 0.														
														0.00000
					0.00000	0.00000	0.00000	0.00000	0.00000	0.05223				0.03170
21 Index 18, NC only: 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.05710 0.48004 0.26810 0.16743 0.	21 Index 18,	NG Only:	0.00000	0.00000	0.0000	4.00000	4,00000	0.00000	0.00000	0.057 10	0.48004	0.26810	0.16743	0.02733

^{*} No Summer/Winter differentiation. Factors derived from negotiated atipulation.

TABLE 3

PACIFIC GAS AND ELECTRIC COMPANY COST ALLOCATION SUMMARY

Forecast Period:	April.	1, 1991 to h	Harch 31, 1992
# # # # # # # # # # # # # # # # # # #		SYSTEM	CORE NONCORE & WHOLESALE
·	ALLOC	COST	COST CORE-ELECT COST
•		(\$000)	(\$000) (\$000) (\$000)
经基本条件 医电影 医电影 医电影 医电影 医克里特氏 医克里特氏 医克里特氏试验检试验			· 李子子 以表示的 电电子 电电子 电电子 医内内氏 电电子 医克克斯氏管 医中枢性 医中枢性
FORECAST PERIOD COSTS	_	80.4/5	4,431 55,517 55 197
Commodity Related Base		10,145 212,600	101,308 107,073 4,218
Transmission Base Storage Base	Č.	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 4 214
50% Adminstrative and General	. m-	88,634	39,074 48,646
Other Operating Revenue	f	. (9, 149)	(7,231) (1,865) (53)
			887,076 228,807 6,540
SUBTOTAL - Base (Margin)		1,122,424	867,076 220,007 10,540
EOR Credit	, h	(12,187)	(9,116) (2,977) (94)
Interutitity Transportation Service		(6,893)	(3,285) (3,472) (137)
Brokerage Fee: Procurement AEG	. J.		0 (5,115)- (183)
Brokerage Fee: Core Marketing	k	(6,389)	(6,389)
Brokerage Fee: Noncore Marketing	l,	(123)	0 (120) (3)
Long Term Contract Revenue	8	(2,858)	(1,248) (1,554) (1,554)
Authorities Authorities Princip		1,088,676	867,038~1215,569013JA6,069
SUBTOTAL - Adjusted Base		1,000,070	
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
Cas Storage Trueup	17	1,708	0 1,612 96 12,012 14,954 534
Take-or-Pay Transition Costs	1	77.7	12,0125 14,954 5 5 5 5 5 5 5 6 6 6 6 6 6 6 6 6 6 6 6
Take-or-Pay Trueup	1 2	20,467 2,628	1,685
CFA Debt Service and Expense Gas Exploration & Development Account			21,839 27,190 971
LUAF & GDU	11	61,841	26,252 34,424 7 7,165
CPUC Fee	12	4,489	2,537 1,952 0
LIRA AEG	- 14	1,961	1,228 733/4 AACC 0 728/3 1999/04 1997 0
RD&D Trueup - Core	19	728	720
RD&D Trueup - Noncore	17	352	11 0년 1 : 4 332년 18년 19 20 : 12 : 12 : 12 : 13 : 14 (13 2)의 원생 (11)
Noncore Base Cost Adjustment	17 20	(193)	0-4 4- (989) - 277 (32)
1990 ACAP F&U Adjustment	21	(1,021) (289)	0 (281) (8)
Corporate Franchise Tax Adjustment Earthquake Recovery Adjustment	n	486	0 10 10 486 910 10
Earthquare Recovery Nojustinoite			***************************************
TOTAL - Forecasted Period Costs	,	1,452,804	1,034,73300,404,928470013,143
AMORTIZATION OF BALANCING ACCOUNTS			TO I SHOW A SAME TO BE A CONTRACTOR
Gas Core Fixed Cost	3	49,873	49,873 736 504 504 0
Noncore Transition Cost	9	(2,699)	0.1 (2),606)\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\
Enhanced Oil Recovery	. 5	(2,492)	(1,874) (599)
A&S Interutility	Sign 6	(109)	(52)************************************
CFA Debt Service and Expense	Ž	(1,327)	(851) 4771 (476) 7 A 77 O
Core TOP	3	. 0	0 0 VD4 0
NGV	1 14	(8,277)	(5,184) (3,093) 🐬 0
LIRA COGEN Shortfall	13	1,106	0 4 1,106 4,440 0
COGEN SHOLLINGE			*********
TOTAL - Forecasted Acct Balances		36,075	41,913 (5,724) (114)
. F&U		13,793	9,962 3,734 5 96
		4 KAN 499"	1,086,607 402,939 13,125
TOTAL - Transport Revenue Requirem	nent	1,502,672	
	·	97	AUL CONTROL ARRUGITETT
G-10 Allocated Employee Discount	. 18	969	772 annow 192 at 15
GC-2 Shortfall		(7,941)	0 - 2 (10):253) 3-33
GC-2 Shortfall Allocated	8	7,941	(17,268)
LIRA Discount Benefits	14	(17,268) 17,268	10,814 (1) 6,454 (4) 2
LIRA Discount Expenses		17,400	
TOTAL - Transport Costs		1,503,641	1,084,473 403,567 13,288
INING - ILBURNOLC ANDER		## # * · ·	

TABLE 4

PACIFIC CAS AND ELECTRIC COMPANY RESIDENTIAL CUSTOMERS COST ALLOCATION CORT Period: April 1, 1991 to March 31, 1992

	,	SYSTEM"	UNADJ.	UNADJ	ADJ	ADJ
	ALLOC	COST	ALLOC	COST	ALLOC	COST
	INDEX	(\$000)	FACTOR	(\$000)	FACTOR	(\$000)
RECAST PERIOD COSTS		10,145	0.29897	3,033	0.30638,	3,108
Commodity Related Base	ē		0.33071	70,309	0.33861	71,989
Transmission Base	ċ	43,869	0.41613	18,255	0.42577	18,678
Storage Base	ď		0.63199	175,027	0.64018	177,294
Distribution Base	ъ.	499,381	0.90179	450,338	0_90179	450,338
Customer Base	- M.	88,634	0.30168	26,739	0.30922	27,407
50% Adminstrative and General	- i	(9,149)	0.65723	(6,013)	.0.66175	(6,054)
Other Operating Revenue			•		· · · · ·	742,761
SUBTOTAL - Base (Margin)	1	,122,424		737,688		
	h	(12,187)	0.61321	(7,473)	0.61819	(7,534)
EOR Credit	•	(6,893)	0.33071	(2,280)	0.33861	(2,334)
Interutility Transportation Service	1.4	(5,298)	0.00000	0	0.00000	. 0
Brokerage Fee: Procurement AEG		(6,389)	0.92025	··· (5,879) ·	0.92025	(5,879)
Brokerage Fee: Core Marketing	· •	(123)	0.00000	0	0.00000	0
Brokerage Fee: Noncore Marketing		(2,858)	0.29897	(854)	0.30638	(876
Long Term Contract Revenue	143	. (2,0)0/	******	*****		
SUBTOTAL + Adjusted Base		1,088,676		721,201		726,138
		176,496	0.33861	59.764	0.33861	59,764
Pipe Demand Charges	6		0.00000	37,100	0.00000	
Pipeline Demand Trueup	: 16 :	2,401 14,574	0.42577	6.205	0.42577	6,205
Gas Storage Carrying Costs	7	14,2/4	0.00000	0	0.00000	0
Cas Storage Trueup	17	1,708	0.29846	8 208	,,0.30638	8,425
Take-or-Pay Transition Costs	1	27,500	0.29846	A 100	0,30638	
Take-or-Pay TrueUP	1			1 110	0,44961	1,182
rea nobr Service and Expense	2	2,628	0.43335	1,107	0.30638	
Gas Exploration & Development Accoun-	τ 1	50,000	0.29846	14,925	0.29794	18,425
LUAF & GDU	11	61,841	0.29688			
CPUC Foe	12	4,489	0.39684	1,781	0.39874	837
	14	1,961	0.41096	806		4. 55.
LIRA ASG	19	728	0.74135	540		540
RD&D Trueup - Core	17	352	0.00000	- 0-	0.00000	
RDED Trueup - Noncore	17	(193)	0.00000	. 0.		Ç
Noncore Base Cost Adjustment	20	(1,021)	0_00000	, 0 .	0.00000	
1990 ACAP F&U Adjustment	21	(289)	0.00000	. 0 .	0.00000	
Corporate Franchise Tax Adjustment Earthquake Recovery Adjustment	'	486	0.00000	0	0.00000	19, 1994
•		* /50 00/		839,035	many'	844,896
TOTAL - Forecasted Period Costs		1,452,804	1,	2.1.2.2.3	1,44	5.51
AMORTIZATION OF BALANCING ACCOUNTS		/0.977	0.70143	34.9825	0.70143	34,,982
Cas Core Fixed Cost	3 0			0-		
Noncore Transition Cost				(1.549)	0.62152	(1,54
Enhanced Oil Recovery					0.33861	(3
ALS Interutility	6	(107)	0.43335	(575)	0.44961	
CFA Debt Service and Expense	2	(1,34/)			0.70143	signik i Erki ^{ere} (j 1981 – 1984)
Core TOP	. 3	. 0	0.10149	\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\		17) + 12
NGV	1	46	U-ZYO-0	/3 /02	0.42702	(3,53
LIRA (12) 12	14	(8,277)	0.41070	ري. م	0.42702	Alexander 1
COCEN Shortfall	13		ψ.Ψυψυ υ	· · · · · · · · · · · · · · · · · · ·	Tarana	
			•	29,420		29,26
TOTAL - Forecasted Acct Balances	A. Jan			1.7 1.52 14	progation pr	.167 8,09
F&U . 1	***	13,793		8,041		
TOTAL - Transport Revenue Require						882,25
	and Charles	. 16th				
ALLOCATION ADJUSTMENTS	11	969 (7,941 3 7,941 (17,268 4 17,268	0.66696	±1646	,,,, 0.66696	_{17 500} 64
G-10 Allocated Employee Discount	Çışılı	(7.941)	- 14 Line C) gg- (+c	. 17:0 <u>.</u>
CC-2 Shortfall	*****	7 7 941	0,30505	2,422	0.31332	2,4
GC-2 Shortfall Allocated	e de la	(17.268)	(17,268	D: 17 +	(17,20
LIRA Discount Benefits		17 248	0_41096	7.096	0.42702	: "∵7,3
LIRA Discount Expenses					**************************************	
•	,			869,394		875.49
TOTAL - Transport Costs	P - 31	1,503,641		MAY 100	•	

TABLE 5A

PACIFIC GAS AND ELECTRIC COMPANY: 1700 SMALL COMMERCIAL (SUMMER) CUSTOMERS COST ALLOCATION (ACC)

****	SYSTEM	LOBAN	UNADJ	ADJ	ADJ
	ALLOC COST		COST	ALLOC	COST
	INDEX (\$000)		(\$000)	FACTOR	(\$000)
DRECAST PERIOD COSTS			-	rje vyje	
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		0.12324	5,406
Distribution Base	d 276,945			0.17262	
Customer Base	b 499,381		38,018		38,015
50% Adminstrative and General	m 88,634	0.10668	9,455		
Other Operating Revenue	1 (9,149			0.11168	
		•			
SUBTOTAL - Base (Margin)	1,122,424		123,795 ···	rena di Li)46روڪا ^ن .
EOR Credit	h:::c12,187		(1,347)	0.11206~	
Interutility Transportation Service	e (6,893		· · · (771)›		
Brokerage Fee: Procurement A&G	J (5,298			0.00000	e generaliza [
Brokerage Fee: Core Marketing	k (6,389				
Brokerage Fee: Noncore Marketing	th: (123			0.00000	
Long Term Contract Revenue	(2,858		(302)	0.10834	(31)
SUBTOTAL - Adjusted Sase	1,088,676		120,879	6.193 ×	122,38
Pipe Demand Charges	6 176,496	0.00000	٥	0.00000	egun on t
Pipeline Demand Trueup	16 2,401			0.00000	أرثو تعردا
Cas Storage Carrying Costs	7 14,574	0.00000		0.00000	
Gas Storage Trueup	17 1,708	0.00000		0.00000	
Take-or-Pay Transition Costs	1 27,500	0.00000		0.00000	
Take-or-Pay Trueup	1 20,467	0.00000		0.00000	
CFA Debt Service and Expense	2 2,628	0.0000		0.00000	
Gas Exploration & Development Account	1 50,000			0.00000	en in transport
	11 61,841			0.04991	
FAUL - AAA	12 4,489	0.04540	20/	0.04554	20
	4/ 4,407	0.00000	£74	0.0000	34 3 4 7
LIRA AEG	14 1,961	0,00000	294 0 0 0	0.00000	
RDED Trueup - Core	19 728	0.00000	, ,		rand sty
RD&D Trueup - Noncore	17' 352	0.00000	U#+,	>U_000000-	15 T Co.
Noncore Base Cost Adjustment	17 (193		0.7		
1990 ACAP FEU'Adjustment	20 (1,021		. 0-		
Corporate Franchise Tax Adjustment:	21 (289		ogus til vil 🔾 🥡		
Earthquake Recovery Adjustment	n- 486	0.00000-		3 0-00000 7	isune: d
TOTAL - Forecasted-Period Costs		. ,	124,249	The state of the	125,76
ORTIZATION OF BALANCING ACCOUNTS		. ,	الله المعادية المسابقة	A 151 - 67 W	rana.
Gas Core Fixed Cost	3 49,873	0.00000	0 -	0.000001	Section 1
			∩ ~	.0.00000-	
Noncore Transition Cost	9 (2,699	7 4.00000			the same of a
Noncore Transition Cost Enhanced Oil Recovery	5 (2,492	> 0.00000	(281)	0_11270^	(28
	5 (2,492 6 (109	0.00000	0	0.00000	أوفر زويه وسا
Enhanced Oil Recovery A&S Interutility	5 (2,492 6 (109	0.00000	0	0.00000 0.00000	ادي زمين ادي زمين
Enhanced Oil Recovery A&S Interutility CFA Debt Service and Expense	5 (2,492 6 (109 2 (1,327	0.00000	0	0.00000 0.00000	ادي زمين ادي زمين
Enhanced Oil Recovery A&S Interutility CFA Debt Service and Expense Core TOP	5 (2,492 6 (109 2 (1,327	0.00000	0 0 0	0.00000 0.00000 0.00000	9461 (38 16A (989 989 (1866) 188
Enhanced Oil Recovery A&S Interutility CFA Debt Service and Expense Core TOP NGV	5 (2,492 6 (109 2 (1,327 3 0	0.00000 0.00000 0.00000	0 0 0	0.00000 0.00000 0.00000	ექიე ეკებ 16გ ეგდეთ სალიც 18ები 18ეგ
Enhanced Oil Recovery A&S Interutility CFA Debt Service and Expense Core TOP NGV	5 (2,492 6 (109 2 (1,327 3 0 1 0 14 (8,277 13 1,106	0.00000 0.00000 0.00000 0.00000 0.00000	0000	0.00000 0.00000 0.00000 0.00000	bib Tatro MA Swed Jame Tiba Ma Ma Massa Ma Massa Massa Massa Massa Massa Massa Massa Massa Massa Massa Ma Massa Ma Massa Massa Massa Massa Ma Massa Ma Massa Ma Massa Massa Ma Ma Massa Massa Ma Massa Ma Ma Ma Massa Ma Ma Massa Massa Massa Masa Ma Ma Massa Massa Ma Ma Ma Ma Ma Ma Ma Ma Ma Ma Ma Ma Ma
Enhanced Oil Recovery A&S Interutility CFA Debt Service and Expense Core TOP NGV	5 (2,492 6 (109 2 (1,327 3 0 14 (8,277 13 1,106	0.00000 0.00000 0.00000 0.00000 0.00000	0	0.00000 0.00000 0.00000 0.00000	lab Cotto MA Coepa Jame 1102 Mari Mari Mari Mari Com Mari Mari
Enhanced Oil Recovery A&S Interutility CFA Debt Service and Expense Core TOP NGV LIRA COGEN Shortfall TOTAL - Forecasted Acct Balances F&U	5 (2,492 6 (109 2 (1,327 3 0 1 (8,277 13 1,106	0.00000 0.00000 0.00000 0.00000 0.00000	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0	0.00000 0.00000 0.00000 0.00000 0.00000	lab Cate MA Svept Jame 1107 Mar Noote cen
Enhanced Oil Recovery A&S Interutility CFA Debt Service and Expense Core TOP NGV LIRA COGEN Shortfall TOTAL - Forecasted Acct Balances F&U	5 (2,492 6 (109 2 (1,327 3 0 1 0 14 (8,277 13 1,106 36,075	0.00000 0.00000 0.00000 0.00000	0 0 0 0 0 0 1,155	0.00000 0.00000 0.00000 0.00000 0.00000	ortes Cald Special And Special Special Special Special Special Special Special Special Special Special Special Special Special
Enhanced Oil Recovery A&S Interutility CFA Debt Service and Expense Core TOP NGV LIRA COGEN Shortfall TOTAL - Forecasted Acct Balances F&U	5 (2,492 6 (109 2 (1,327 3 0 1 0 14 (8,277 13 1,106 36,075	0.00000 0.00000 0.00000 0.00000	0 0 0 0 0 0 1,155	0.00000 0.00000 0.00000 0.00000 0.00000	ortes Cald Special And Special Special Special Special Special Special Special Special Special Special Special Special Special
Enhanced Oil Recovery A&S Interutility CFA Debt Service and Expense Core TOP NGV LIRA COGEN Shortfall TOTAL - Forecasted Acct Balances F&U TOTAL - Transport Revenue Requirement LOCATION AD HISTMENTS	5 (2,492 6 (109 2 (1,327 3 0 14 (8,277 43 1,106 36,075 13,793	0.00000 0.00000 0.00000 0.00000 0.00000	(281) 1,155	0.00000 0.00000 0.00000 0.00000 0.00000	9461 (28 5962 A M 597 (946) 597 (946) 647 (28 1,16 126,65
Enhanced Oil Recovery A&S Interutility CFA Debt Service and Expense Core TOP NGV LIRA COGEN Shortfall TOTAL - Forecasted Acct Balances F&U TOTAL - Transport Revenue Requirement LOCATION ADJUSTMENTS Cold All Control Employees Discount	5 (2,492 6 (109 2 (1,327 3 0 14 (8,277 13 1,106 36,075 13,793	0.00000 0.00000 0.00000 0.00000 0.00000	(281) 1,155	0.00000 0.00000 0.00000 0.00000 0.00000	0.46.1 (2.6 https://doi.org/10.46.1 (2.8 https://doi.org/10.46.65.65.65.65.65.65.65.65.65.65.65.65.65
Enhanced Oil Recovery A&S Interutility CFA Debt Service and Expense Core TOP NGV LIRA COGEN Shortfall TOTAL - Forecasted Acct Balances F&U TOTAL - Transport Revenue Requirement LOCATION ADJUSTMENTS Cold All Control Employees Discount	5 (2,492 6 (109 2 (1,327 3 0 14 (8,277 13 1,106 36,075 13,793	0.00000 0.00000 0.00000 0.00000 0.00000	(281) 1,155	0.00000 0.00000 0.00000 0.00000 0.00000	0.46.1 (2.6 https://doi.org/10.46.1 (2.8 https://doi.org/10.46.65.65.65.65.65.65.65.65.65.65.65.65.65
Enhanced Oil Recovery A&S Interutility CFA Debt Service and Expense Core TOP NGV LIRA COGEN Shortfall TOTAL - Forecasted Acct Balances F&U TOTAL - Transport Revenue Requirement LOCATION ADJUSTMENTS G-10 Allocated Employee Discount GC-2 Shortfall GC-2 Shortfall Allocated	5 (2,492 6 (109 2 (1,327 3 0 14 (8,277 13 1,106 36,075 13,793 14 17,502,672	0.00000 0.00000 0.00000 0.00000 0.00000	(281) 1,155 125,123	0.00000 0.00000 0.00000 0.00000 0.00000 0.00000	1,166 2017 2019 2017 2019
Enhanced Oil Recovery A&S Interutility CFA Debt Service and Expense Core TOP NGV LIRA COGEN Shortfall TOTAL - Forecasted Acct Balances F&U TOTAL - Transport Revenue Requirement LOCATION ADJUSTMENTS G-10 Allocated Employee Discount GC-2 Shortfall LIRA Discount Benefits	5 (2,492 6 (109 2 (1,327 3 0 1 0 14 (8,277 13 1,106 36,075 13,793 15 1,502,672 18 969 (7,941 8 7,941	0.00000 0.00000 0.00000 0.00000 0.00000 0.00000	(281) 1,155 125,123	0.00000 0.00000 0.00000 0.00000 0.00000 0.00000	126,656
Enhanced Oil Recovery A&S Interutility CFA Debt Service and Expense Core TOP NGV LIRA COGEN Shortfall TOTAL - Forecasted Acct Balances F&U TOTAL - Transport Revenue Requirement LOCATION ADJUSTMENTS G-10 Allocated Employee Discount GC-2 Shortfall LIRA Discount Benefits	5 (2,492 6 (109 2 (1,327 3 0 1 0 14 (8,277 13 1,106 36,075 13,793 15 1,502,672 18 969 (7,941 8 7,941	0.00000 0.00000 0.00000 0.00000 0.00000 0.00000	(281) 1,155 125,123	0.00000 0.00000 0.00000 0.00000 0.00000 0.00000	126,656
Enhanced Oil Recovery A&S Interutility CFA Debt Service and Expense Core TOP NGV LIRA COGEN Shortfall TOTAL - Forecasted Acct Balances F&U TOTAL - Transport Revenue Requirement LOCATION ADJUSTMENTS G-10 Allocated Employee Discount GC-2 Shortfall GC-2 Shortfall Allocated	5 (2,492 6 (109 2 (1,327 3 0 1 0 14 (8,277 13 1,106 36,075 13,793 15 1,502,672 18 969 (7,941 8 7,941	0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000	(281) 1,155 125,123	0.00000 0.00000 0.00000 0.00000 0.00000 0.00000	126,656 126,656

TABLE 58: 14

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

Forecast Period: April 17 1991 to March 31, 1992 and

$\frac{1}{2} \frac{1}{2} \frac{1}$	ALLOC:	SYSTEM	ALLÓC	LDANU T2Q ɔ	ALLOC ALLOC	ADJ COST
	INDEX	(\$000)		(\$000)	FACTOR	(\$000)
RECAST PERIOD COSTS						
Commodity Related Base		10,145		0	0.00000	s warre
Transmission Base	• 5	212,600	0.00000	0	0.00000	, haden d'0
Storage Base		43,869	0.00000		0.00000	
Storage Base Distribution Base Sustomer Base		276,945	0.00000	0	0.00000	a de la Company
Lustomer Base	b- .	499,381		0	0.00000	
50% Adminstrative and General	mè,	88,634	0.00000		0.00000	· · · · · · · · · · •
Sustamer same 50% Administrative and General Other Operating Revenue	1	(9,149)	0.00000	·a 0 -		egt nevid
SUBTOTAL - Base (Margin)						a introd 0
EOR Credit	h∴.	(12,187)	0.00000	00	0.00000	<u>.</u>
Interutility Transportation Service.		∵(6,89 3)	0.00000	u in ing On	0.00000	(A.4.1.0
Brokerage Fee: Procurement A&G	i	(5,298)	0.00000	Q+	.0.00000	is, File 0
Brokerage Fee: Core Marketing	k	(6,389)	0.00000	c	.~0.00000	in all sides 🔾
Brokerage Fee: Noncore Marketing	L	(123)	0.00000	- Or	0.00000	118 1 V
ong Term Contract Revenue	8	(2,858)	0.00000	, s .o .s.	0.00000	
SUBTOTAL - Adjusted Base	1	,088,676		: 0-	·	
•		176,496	0.11452	20.21%	0.11452	. 20 213
Pipe Demand Charges Pipeline Demand Trueup	14.	2,401			0.00000	
ripetine Demand FreeD	7	14,574	0.12324		0.12324	
Gas Storage Carrying Costs Gas Storage Trueup	17	1,708	0.00000		0.00000	
as Storage Trueup						
Take-or-Pay Transition Costs	1 .	27,500	0.10554	. 2,902	0.10834	. 1.2 p71.7
fake-or-Pay Trueup	J	20,467	0.10554	2,100	0.10834	7اکس که د
CFA Debt Service and Expense	2	2,628	0.15324	403	0.15899	418
ias Exploration & Development Account	- 1.	50,000	0.10554	5,277	0.10834	5,417
UAF & COU	11	61,841	0.05504	3,404	0.05524	3,416
IPUC Fee	12.	4,489	0.07238	325	0.05524	326
LUAF & GOU PUC Fee LIRA A&G	14.	1,961	0.15929	312	0.10332	
ROED Trueup - Core	19	728	0.21458	156	0.21458	156
SAPA Tallacia - Namanan	17	352	0.00000	0-	0.00000	
Noncore Base Cost Adjustment 1990 ACAP F&U Adjustment	17	(193)	0.00000	.0	0.00000	id 59 m2€
1000 ACAD FELL Adjustment	20.		0.00000	7 0	0_00000	640 J. 24.0
Corporate Franchise Tax Adjustment	21	(289)	0.00000	0	0.00000	A 140 (40)
Earthquake Recovery Adjustment	0	486	0.00000		0.00000	
car cudoada kacasai à voluntimand						
TOTAL - Forecasted Period Costs	. "1	,452,804	. *	36,949	, , , , ,	37,263
ORTIZATION OF BALANCING ACCOUNTS	ψ.	· /0 977	0.24804		0.24804	
Cas Core Fixed-Cost	».	49,873 (2,699)	0.00000		0.00000	
Honcore Transition Cost	9	(2,699)	0.00000			
	5•	(2,492)	0.00000	0	~~0.00000	90م)ئايدىن قەم
A&S Interutility	•	(109)	0.11452	(12)	0.11452	€12 • • • • • • • • • • • • • • • • • • •
CFA Debt Service and Expense		(1,327)	0.15324		0.15899	(211
Core TOP	3	.0				95
NGV	1		0.10554	0		
LIRA	14	(8,277)	0.15929	(7,318)	0.16552	(1,370
COGEN Shortfall	13:	1,106	0.00000	0	0.00000	0يلوم درس
TOTAL - Forecasted Acct Balances	- + 4,	c36 , 075		10,836	of the view	- 10,777
	⁻	ः 1 3,793		599		432
F&U						/ B / 77
	nt 971	,502,672	The second second	40,505		40,412
F&U TOTAL - Transport Revenue Requirement LOCATION ADJUSTMENTS				y,	ر پروازی راهید د بره	. ACCESTO
TOTAL - Transport Revenue Requirement	18.	969	0.00000	y,		. ACCESTO
TOTAL - Transport Revenue Requirement LOCATION ADJUSTMENTS G-10 Allocated Employee Discount	18.	969	0.00000		0.00000	i ag i rappi ng chi bira nesta iya C
TOTAL - Transport Revenue Requirement LOCATION ADJUSTMENTS G-10 Allocated Employee Discount GC-2 Shortfall	1 8 1	969 3 (7,941)	0.00000		0.00000	i ag i rappi ng chi bira nesta iya C
TOTAL - Transport Revenue Requirement LOCATION ADJUSTMENTS G-10 Allocated Employee Discount GG-2 Shortfall GG-2 Shortfall Allocated	181 192,	969 (7,941) 7,941	0.00000	0 0 857	0.00000	. 2017/00:0 64:04:07:0 66:44:18:06:0 6:44:18:08:08:08:08:08:08:08:08:08:08:08:08:08
TOTAL - Transport Revenue Requirement LOCATION ADJUSTMENTS G-10 Allocated Employee Discount GG-2 Shortfell GG-2 Shortfell Allocated LIRA Discount Benefits	18	969 (7,941) 7,941 (17,268)	0.00000	0- 0 857	0.00000	. 2017/1000 241/4 01/4 26/4/1000 36/4/1000 36/4/1000
TOTAL - Transport Revenue Requirement LOCATION ADJUSTMENTS G-10 Allocated Employee Discount GG-2 Shortfall GG-2 Shortfall Allocated	18	969 (7,941) 7,941	0.00000	0- 0 857	0.00000	. 2017/1000 241/4 01/4 26/4/1000 36/4/1000 36/4/1000

TABLE 64

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

	ALLOC	COST (\$000)	UNADJ ALLOC FACTOR	UNADJ COST	ADJ ALLOC FACTOR	ADJ: COS3)
DRECAST PERIOD COSTS						one of the second
Commodity Related Base		10,145	0.00000	, 0	0.00000	tita e e
Transmission Base	11, 🖷 📜	212,600	0.00000	0	0.00000	· / 116 *
Storage Base	, C.,		0.00000			2 March 2 6
Distribution Base			0.00000	0		
Customer Base	þ.		0.00000		0.00000	
50% Administrative and General		88,634	0.00000	0	0.00000	
Other Operating Revenue	and the second	(9,149)	0.00000	0	0.00000	
******		,122,424			, , , , , , , ,	
SUBTOTAL - Base (Margin)						
EOR Credit		(12,187)	0.00000	0	0.00000	
Interutility Transportation Service		(6,893)	0.00000	Ų,	., 0.00000	**
Arokerage Fee: Procurement A&G		(5,298)	0.00000	0	0.00000	
Rrokerage Fee: Core Marketing	K.	(6,389)	0.00000	0	0.00000	
Brokerage Fee: Noncore Marketing	٠ ل			, _{ke a} O	0.00000	· No Line
Long Term Contract Revenue	·. •	(2,858)	0_00000	0	, 0.00000	
	. •					
SUBTOTAL - Adjunted Bane	- 1	,088,676		.0,	1	7 11 1
Pipe Demand: Charges	6	176,496	0.00000		.,0.00000	
Pipeline Demand Trueup	16	2,401	0.00000		0.00000	
Gas Storage Carrying Costs	7	14,574	0.00000	0,		ta a≱a a a a a a a a a a a a a a a a a a
Cas Storage Trueup	17	1,708	0.00000	0.	0.00000	
	1		0.00000	0	0.00000	a fill officers
Take-or-Pay Transition Costs	1		0.00000	Ö	0.00000	The street of the street
Take-or-Pay Trucup			0.00000	ŏ	0.00000	
CFA Debt Service and Expense	2	2,040		ŏ	0.00000	7# 1 55g
Gas Exploration & Development Accou	int 1				0.00000	the state of
LUAF & CDU	11 ·		0.00000		0.00000	
CPUC Fee	12	4,489		_		
LIRA AEG	.74	1,961	0.00000			
ROLD Trueup - Core	. 19	728	0.00000	Q	0.00000	
RD&D Trueup - Noncore	17	352	0.00000	.,.0,	0.00000	
Noncore Base Cost Adjustment	17	(193)	0.00000		0.00000	
1990 ACAP FEU Adjustment	20	(1,021)	0.00000	0		
Corporate Franchise Tax Adjustment	. • 21	(289)	0.00000	0	്റ.00000	
Earthquake Recovery Adjustment	5″# ∩	- 456	0.00000	<u> </u>	0.00000	i de la companya de La companya de la co
TOTAL - Forecasted Period Costs		1,452,804	e.	0	· . • .	
MORTIZATION OF BALANCING ACCOUNTS						
Gas Core Fixed Cost	3	49,873	0.00000	0,	0.0000	
Noncore Transition Cost	9	(2.699)	0.00000	0	0.00000	i Servicio de Constitución de
	5	(2,492)	0.00000	· · · · · · · · · · · · · · · · · · ·		
Enhanced Of L Recovery	6	(109)	0.00000	``` ` ``	0.00000	19 11 11 11 11 11 11 11 11 11 11 11 11 1
A&S Interutility CFA Debt Service and Expense	ž		0.00000	U	u.uuuuu	
=		0,32,7		` ` ` ' ` ' ` '	0.00000	own Ast
Core TOP	9 9			-	0.00000	
NCV	· · · · · · · · · · · · · · · · · · ·	(8,277)	0.00000	ň	0.00000	
LIRA	14	(0,2//)	0.00000	, .	0.00000	\$ 1.5
COGEN Shortfall		1,106			0.00000	
TOTAL - Forecasted Acct Balances	11, 3	36,075		ويواريد المعامرات	e territorio de	
FZU	13 27	13,793		0	_	
		4 502 672	.,	0	•	
TOTAL - Transport Revenue Require					-	•
LLOCATION ADJUSTMENTS G-10 Atlocated Employee Discount		. 040	0.00000	377 X	n none	MALC: Y
G-10 Allocated Employee Discount	18	769	0.00000	Salaton Salaton		33.40
GC-2 Shortfall	111	(7,941)				
GC-2 Shortfall GC-2 Shortfall Allocated		7,941	0.00000		0.00000	/ 3 % ·
LIRA Discount Benefits LIRA Discount Expenses		(17,268)		´.,,0	to the second	and the second second
PUMA BIRCAMIC BALLELLON	131 194	17 268	0.00000	0	0.00000)
I TOA NECKUMP FYRANSAS	(4).					
LIRA Discount Expenses	and a gradual service of				•	

TABLE 68-A"

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

54,866887676768888888888888	ALLOC	SYSTEM COST (\$000)	UNADJ ALLOC FACTOR	LOANU	ADJ ALLOC FACTOR	ADJ COST (≤000)
A 12 20 0 20 20 20 20 20 20 20 20 20 20 20						
FORECAST PERIOD COSTS			0.00000	. 0	0.00000	-1 50 ,8 N - 1,0
Commodity Related Base		10,145 212,600	0.00000			
Transmission Base		43,869	0.00000		0.00000	
Storage Base Distribution Base	d	276.945	0.00000	0	0.00000	0
Customer Base	5	499,381	0.00000		0.00000	
50% Adminstrative and General	m ·	88,634	0.00000		. 0.00000	
Other Operating Revenue	2 to 1 4		0.00000	· Q ·.	0.00000	0
SUBTOTAL - Base (Margin)		,122,424		0		0
EOR Credit	· .	(12,187)	0_00000	0	0.000005	
Interutility Transportation Service		(6,893)	0.00000	.0.	0.00000	0
Brokerage Fee: Procurement A&G	1 .	(5.298)	0_000004		···0.00000,	0
Brokerage Fee: Core Marketing	k	(6,389)	0.00000	1 7 V 04	0.00000	i Karang 🍳
Brokerage Fee: Noncore Marketing		(123)		- 14.5 G eo	0.00000	ng projektive 💆
Long Term Contract Revenue		(2,858)	0.00000		0-40000	ur yayy U
		1 Agg 474		. A.	egi kalan jisa	
SUBTOTAL - Adjusted Base	. 1	,088,676		U'.		Instal
Pipe Demand Charges		176,496		0.	0.00000	of Herold
Pipeline Demand Trueup	16	2,401	0.00000	0	0.00000	
Cas Storage Carrying Costs	7	14,574	0.00000	0.	0.00000	
Cas Storage Trueup	1.7		0.00000		0.00000	Ō
Take-or-Pay Transition Costs Take-or-Pay Trucup		20,467	0.00000	Ď.	0.00000	0
CFA Debt Service and Expense	2	2,628	0.00000	0	0.00000	0
Gas Exploration & Development Acco		50,000	0.00000		0.00000	0
LUAF & CDU	11	61,841	0.00000	Ō	0.00000	
CPUC Fee	12	4,489		0	0.00000	is allig 0
LIRA ASC	14	1,961	0.00000	0	0.00000	
RDED Trueup - Core	19	728	0.00000	Ú.	0.00000	. 0
RD&D Trueup - Noncore	17 17	(193)	0.00000	0-	0.00000	
Noncore Base Cost Adjustment	20	(1,021)			0.00000	Ô
1990 ACAP F&U Adjustment Corporate Franchise Tax Adjustmen		(289)	0.00000	100	0.00000	ing and a O
Earthquake Recovery Adjustment	ั การกัก เ	486		0.	0.00000	0
TOTAL - Forecasted Period Costs	*14 I 14	1,452,804	,	0-	e som sill to the second	A5727 0
AMORTIZATION OF BALANCING ACCOUNTS			279 9	an in the .		A. 780 W.
Cas Core Fixed Cost	3	49,873	0.00000	, <u>Q</u> ,	0.00000	ດວົ່ອຍິລ <mark>0</mark>
Noncore Transition Cost	1 (NO), 9 1 (NO), 9	(2,699)	0.00000		, , 0,0000	termore 0
Enhanced Oil Recovery	5	(2,492)		γ: α υ γ	0.00000	ACTUAL TO A
ALS Interutitity CFA Debt Service and Expense	2	(1,327)	0.00000		0_00000	
Core TOP	. 3	0	0.00000	··	0.00000	7 200
NGV	1	; 0	0.00000	0	0.00000	- y _{ob} 9
LIRA		(8,277)	0.00000	0	0.00000	Add 3
COGEN Shortfall	13	₹1,106	0.00000	0	0.00000	V3003
TOTAL - Forecasted Acct Balance	s Sant	36,075	.** /	· ,, 0		47CY C
fæu		13,793		0		<i>()</i> : C
TOTAL - Transport Revenue Requi	rement 1000	1,502,672	9 ,	ong an jod	i January * 1 v 1 i	
ALLOCATION ADJUSTMENTS				11.712.14	e moje si jesti i i i i i i i i i i i i i i i i i i	7.500
G-10 Allocated Employee Discount	18	: 969	0.00000	or grys . O	0.00000	
and the standard of the standa		(7,941)		0	مسرعون والقروات	, Julius C
GC-2 Shortfall Allocated	i'e√', R	7.941	0.00000	marin significa	0.00000	
LIRA DISCOUNT BENETITS	4.5.1	(17,268)		· · · · · · · · · · · · · · · · · · ·	0.00000	
LIRA Discount Expenses	4. 14	17,268	0_00000	0	0.00000	
TOTAL - Transport Costs	and the second	1,503,641		espera		, ₂₇ (

TABLE 7A

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

Forecast Period:	April 1	, 1991 to	March 31,	1992		
4 7 2 2 2 2 2 7 7 P P P P P P P P P P P P	<u> </u>	SYSTEM	UNADJ	UNADJ	ADJ	ADJ
	ALLOC	COST	ALLOC	COST	ALLOC	COST
the second secon		(\$000)	FACTOR		FACTOR	(\$000)
	,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,		******	********		*********
FORECAST PERIOD COSTS				244	A 62267	224
Commodity Related Base		10,145	0.02154	210 / 855	0.02207	4,971
Transmission Base	•	212,600 43,869	0.02473			1,110
Storage Base		276,945	0.03505	9.708	0-03551	9,834
Distribution Base Customer Base		499,381	0.00202	1,008	0.00202	1,008
50% Administrative and General	m	88,634	0.02173	1,926	0.02228	1,974
Other Operating Revenue	₽∵	(9,149)	0.01662	(1 52):	0.01690	(d. 199 7 (.155)
	•					40 6/7
SUBTOTAL - Base (Margin)	1	,122,424		18,649	***	18,967
	- 1 _N	(12: 187)	0-01745	(213)	0.01777	~ · · ·(217)
EOR Credit Interutility Transportation Service		(6,893)	0.02284	(157)	0.02338	(161)
Brokerage Fee: Procurement ANG	Ĭ		0_00000^	0.0	0.00000	gger i des en 🔘 🗀
Brokerage Fee: Core Marketing	ķ.		0.00206	€± .<13>°	0.00206	g (1 3) -
Brokerage Fee: Noncore Marketing	l,	(123)			0.00000	og 1603 by 0
Long Term Contract Revenue	•	(2,858)	0.02154	(62)	. 0.02207	· (63)
		,088,676		18,204	*** b - * - *	18 513
SUBTOTAL - Adjusted Base	* * * * 7	,000,070		10,200		S. C. 107212
Pipe Demand Charges	6.5	176,496	0.00000	012	-0.00000	· · · · · · · ·
Pipeline Demand Trueup	16	2,401	0.00000	· . O• .	0.00000	or as no
Gas Storage Carrying Costs	7	14,574	0.00000	0	0.00000	ozari, i 🍳 -
Cas Storage Trueup	17	1,708	0.00000	_	0.00000	
Take-or-Pay Transition Costs	1 .		0.00000		0.00000	
Take-or-Pay Trueup	2	2,628	0.00000			oligička 🗖
CFA Debt Service and Expense Gas Exploration & Development Account				0	0.00000	
LUAF & GDU	117		0.01006	622	0.01010	624
CPUC Fee	-12	4,489	0.01205			., 60
LIRA AEG	14	1,961	0.00000	_		224 AV
RDED Trueup - Core	19	728	0.00000		0.00000	647 (2011 0) 657 (2014 0)
RDED Trueup - Noncore	17 17	352	0.00000			0
Noncore Base Cost Adjustment	20	(193)	0.00000	0	0.00000	0
1990 ACAP FEU Adjustment Corporate Franchise Tax Adjustment	21	(289)	0.00000			
Earthquake Recovery Adjustment		486	0.00000-			Commission 0
TOTAL - Forecasted Period Costs	200	1,452,804	. ,	18,880	1. No. 1.2 (1. 1. 1.	35,5, 19,19 7
AMORTIZATION OF BALANCING ACCOUNTS			120		at was	
Gas Core Fixed Cost	`` 3 ′∞					erea dua 🍳 -
Noncore Transition Cost	9			0.0	0.00000	Khuppagai 0
Enhanced Oil Recovery	5 6	(2,492)	0.01789	· (45):	70.01759	7, 17, 14, (45)
AGS INTERMITIES	9	(109) (1,327)	0.00000		0_00000	0
CFA Debt Service and Expense	3	0			0.00000	ຕ້າຍ ວ່ 0
Core TOP	1	0	0.00000	0		5. ya 0
LIRA	14	(8,277) 1,106	0.00000	0	0.00000	
COGEN Shortfall	13	1,106	0.00000	0	0.00000	er was o
TOTAL - Forecasted Acct Balances	, 4	36,075	e. or 1.	2755 (45)	cest per c	,ator (45)
	45.7	13,793		175		178
F&U	e					
TOTAL - Transport Revenue Requirem	ent: 🕟	1,502,672	2.5.5	19,011	10 to 10 to 10	∋∧ ::1 9,331
ALLOCATION ADJUSTMENTS				2143	51 <u>, 450, 250, 2</u>	Of Alleman
	18	969	0.01700	00 - 50 16 0	, 0,01700	14. geva 16.
CC-2 Shorffall		(7,941) 7,941	A 8888A	0 	0.00000	eg Gaya Oli Garana Oli
GC-2 Shortfall Allocated		7,941 · (17,268)	0.00000	355 7 357 0 37 3 3 6 6 €	0.00000	
	A. 14	17,268	0.00000	0	0.00000	
LIRA Discount Expenses		17,200				
YOTAL - Transport Costs	" AST LE	1,503,641		19,028	e and the	.a.y 19,347

TABLE 78 A

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

		SYSTEM	UNADJ	LOWIN	ADJ	ADJ
FORECAST PERIOD COSTS Commedity Related Base	ALLOC	COST (\$000)	ALLOC FACTOR	COST (\$000)	ALLOC FACTOR	
FORECAST PERIOD COSTS				-		Su 200
Commodity Related Base					.0.00000	47.779
Transmission Base	- €	212,600	0.00000		0.00000	
Storage Base	¢	43,869	0.00000		0.00000	
Distribution Base Customer Base	. d	276,945	0.00000	0	0_00000	
Customer Base	b	499,381	0.00000	0	0.00000	
50% Adminstrative and General	. m	88,634	0.00000	, 0	0.00000	100
Other Operating Revenue	4,	88,634 (9,149)	0.00000	9, 42 0	0.00000	(1) (1) (1) (1) (1)
SUBTOTAL - Base (Margin)		,122,424		· 0	•	tsat.
EOR Credit	11. h.	(12,187)	0.00000	0	0.00000	
Interutility Transportation Service	e:	(6,893)	0.00000		0.00000	4, 11, 11
Brokerage Fee: Procurement A&G Brokerage Fee: Core Marketing	. j	(5,298)	0.00000	. 0	0.00000	er andere er
Brokerage Fee: Core Marketing	ĸ	(6,389)	0.00000	0	0.00000	
Brokerage Fee: Noncore Marketing	Ĺ	(123)	0.00000	. 0	0.00000	4
Brokerage Fee: Noncore Marketing Long Term Contract Revenue		(2,858)	0.00000	0.	0.00000	
	•					
SUBTOTAL - Adjusted Base		,088,676		, , u ,		·, · · · ·
Pipe Demand Charges Pipeline Demand Trueup	6	176,496	0.02338	4,127	0.02338	
		2,401			0.00000	
Gas Storage Carrying Costs	7	14,574	0.02531	369	0.02531	,,, j. 3 0
Gas Storage Trueup	17	1,708	0.00000	0;	0.00000	
Take-or-Pay Transition Costs	1.	27,500	0.02150	591	0.02207	. 6
Take-or-Pay Trueup	3 - A	20,467	0.02150	440,	0.02207	ran aray 😜
CFA Debt Service and Expense Gas Exploration & Development Account	2	2,628	0.03122	. 82	0.03239	dec in
Gas Exploration & Development Account	1	50,000	0.02150	1,075	0.02207	1,1
LUAF & COU	11.3	61:,841	0.01128	695	0.01132 0.01495	-40 - 120 A
CPUC Fee	12	4,489	0.01352	61	0.01495	a sa sa jargit
	14	4,489 1,961 728	0.03245	64	0.03372	
RD&D Trueup - Core	19	. 728	0.04406	32 , .	0.04406	
RD&D Trueup - Noncore	17	352	0.00000	. 0	0.00000	er Budd
Noncore Base Cost Adjustment	17	(193)	0.00000		0.00000	States and
1990 ACAP FEU Adjustment	20	(1,021)	0.00000	0	0.00000	
Corporate Franchise Tax Adjustment				. 0	0.00000	7. 8 1 7.
Earthquake Recovery Adjustment	n -	486	0.00000	- J O	0.00000	
TOTAL - Forecasted Period Costs	1	,452,804		7,538		, 7,6 0
AMORTIZATION OF BALANCING ACCOUNTS				Service .		.61. 25.4
Gas Core Fixed Cost		49,873		2,520	0.05053	2,5
Noncore Transition Cost	. 9	(2,699)	0.00000	, O.,	0.00000	المحاول المالية
Enhanced Oil Recovery	. 5	(2,492)	0.00000	.0 `.	.0.00000	
A&S Interutility	44.16	(109)	0.02338	(3)	0.02338	
CFA Debt Service and Expense	2	(1:,327)	0.03122	(41)	,, 0.03239	, , , , , , , , , , , , , , , , , , ,
Core TOP	3	0	0.05053	¢	0.05053	111
NCV	. 1	. 0	0.02150	0	0.02207	
LIRA	14	(8,277)	0.03245	(269)	0.03372	(2
COGEN Shortfall	13	1,106	0.00000	(269) 0 2,208.	0.00000	£
				2.208		2,19
TOTAL - Forecasted Acct Balances	• • • •	36,075		-,	1781	
FRU	e per e	13,793		88		
F&U		13,793		88		
F&U TOTAL - Transport Revenue Requireme		13,793		88		
F&U TOTAL - Transport Revenue Requireme	ents, c1	13,793 ,502,672 .	·	88 9,833	j. 18. 9	9,8
F&U TOTAL - Transport Revenue Requireme ALLOCATION ADJUSTMENTS G-10 Allocated Employee Discount	nt 1	13,793 ,502,672 -	0.00000	88 9,833		9,81
F&U TOTAL - Transport Revenue Requireme ALLOCATION ADJUSTMENTS G-10 Allocated Employee Discount	nt 1	13,793 ,502,672 -	0.00000	9,833 0	0.00000	9,8
F&U TOTAL - Transport Revenue Requireme ALLOCATION ADJUSTMENTS G-10 Allocated Employee Discount GC-2 Shortfall GC-2 Shortfall Allocated	nt 18	13,793 ,502,672 	0.00000	9,833 0 0	j. 18. 9	9,8
F&U TOTAL - Transport Revenue Requireme ALLOCATION ADJUSTMENTS G-10 Allocated Employee Discount GC-2 Shortfall GC-2 Shortfall Allocated	nt 18	13,793 ,502,672 	0.00000	9,833 0 0	0.00000	0.83 \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$
F&U TOTAL - Transport Revenue Requireme ALLOCATION ADJUSTMENTS G-10 Allocated Employee Discount GC-2 Shortfall GC-2 Shortfall Allocated LIRA Discount Benefits LIRA Discount Expenses	18 34,01	13,793 ,502,672 . -969 (7,941) 7,941 (17,268) 17,268	0.00000 0.02198 0.03245	9,833 0 0	0.00000 0.02257 0.03372	0.03 E \$

TABLE 8 9 1/2

PACIFIC GAS AND ELECTRIC COMPANY P2B CUSTOMERS COST ALLOCATION

12 2 2 2 2 4 2 4 2 4 2 5 2 5 2 5 2 5 2 5	ALLOC	24000 N	UNADJ ALLOC FACTOR	COST (\$000)	ADJ ALLOC FACTOR	ADJ COST (\$000)
化环环环烷 化氯化甲烷 化苯甲烷 医克克氏征 医克拉克氏 计分析 化非正常化学 电电子		*****	- 14 24 24 24 2 4 24 24			244
RECAST PERIOD COSTS		10,145	0_02415	245	0.02401	4,922
Commodity Related Base	-	212,600	0.02331	4,955	0.02315	
Transmission Base		43,869	0.02023	887	0.02007	881
Storage Base	C	276,945	0.01679	4,651	0.01650	4,570
Distribution Base	d	2/0,747	0.00125	625	0.00125	625
Customer Base	ь ь	499,381	0.02437	2,160	0.02423	2,148
50% Administrative and General	m∙,	88,634	0.02437	(109)		(108)
Other Operating Revenue	•	(9,149)	0.01193		,	
Other Charactus source	•		_	13,414		13,280
SUBTOTAL - Base (Margin)	7	1,122,424		,5,4.4		. P.
SOBIOINE - BELL AND A			4 647/9	/1443	0.01336	(163)
and the state of t	h.	(12,187)	0.01348		0.02315	(160)
EOR Credit Interutility Transportation Service	•	(6,893)		(223)	0.04263	(226)
Interutitity (ransportation A&G	j	(5,298)	0.04209	(223)	0.00000	
Brokerage Fee: Procurement A&G Brokerage Fee: Core Marketing	k	(6,389)	0.00000	. (8)		
Brokerage Fee: Core Harketing		(123)				
Brokerage Fee: Noncore Marketing		(2,858)	0.02415	(69)	9.05.40	
Long Term Contract Revenue	_					12,655
. •	· ·	1,088,676		12,790	100	- A
SUBTOTAL - Adjusted Base						4,086
	A	176,496	0.02315	4,086	0.02315	
Pipe Demand Charges	16	2,401	0.04422		0.04422	293
pineline Demand Trueup	7		0.02007	293		
Cas Storage Carrying Costs	17		0-04716	81		
Car Storage TrueuD	37	27,500		663	0.0240	
Take-or-Pay Transition Costs	1			493		491
Y-U-AAR-DAY TPUBUD	1	20,467		92	0.0352	
C	. 2					1,200
Gas Exploration & Development Accou	unt 1			,,,,,,		2 1,486
LUAF & COU		61,841		ŏ	0.0321	5 144
LUAF & GOV		4,489				8 77
CPUC Fee	14				0.0000	
LIRA AEG	19				0.0471	
RDED Trueup - Core	17	7 . 352				ዿ፝ዀዀዀዀፘ
RDED Trueup - Noncore	17	(193	0.04716			
Noncore Base Cost Adjustment	20	(1,021	0.05222			
1990 ACAP FEU Adjustment			0.05710			
Corporate Franchise Tax Adjustment		480				
Earthquake Recovery Adjustment	,					24.75
• •		1,452,80		19,868	3	21,35
TOTAL - Forecasted Period Costs		1,450,44				
AMORTIZATION OF BALANCING ACCOUNTS				بعثى في المالية	0.000	00
Gas Core Fixed Cost	. Č.	3 49,87	3 0.00000		₹\``0.042	63 ⁰⁰⁰ 6 (11
CAR COLO LINAR CORL		9 (2,69	9) 0.0419			220 1 30 1 (
Noncore Transition Cost		5 (2,49		•	3)0.023	15000000
Enhanced Oil Recovery	**	6 (10			67, 0.035	23''
ALS Interutility	•	2 (1,32	7) 0.0350			
CLY DEDE 241 A LOG MILE AND THE		3	0.0000	•	- 4 45/	A 40 1 19 11 11 11 11 11 11 11 11 11 11 11 1
Core TOP		1	0 0.0241]		
NGV		14 (8,27	77) 0.0363	y (30	0.000	000 1,541
LIRA		13 1,10	0.0000	U		****
COGEN Shortfall						(5
	DC.	36,0	75	. (49	/6)	- 3475
TOTAL - Forecasted Acct Balance	, 					1
	٠٠٠, ١	13,7	93		51	
FEU PROPERTY OF THE PROPERTY O						24.6
	المحمورة	1 502 6	72"	19,5	53 _{0%6} ,	18701
TOTAL - Transport Revenue Requ	1 L G ALLEGE 1. 2					
ALLOCATION ADJUSTMENTS		^	40 0 044	6 % .	11 0.01	163
		(7,9	141)		96 0.02	455
a attached Allocator	. , , , ,		M-1 U-U24	المارية والمناجس	0	
GC-2 ShortTall Allocated		(17,2	(68)		28' '0'0"	8668
LIRA Discount Benefits		14 17.2	(68) (68 0.036	39	140; , V.V.	- Audanee
LIRA Discount Expenses				•••		~ .
CINC DIRECTION		1,503,6			588	

Alexander Const.

250-30-02JA

TABLE 9 Popular

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

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

Forecast' Period:	April 1	, 1991 to M	larch 31, 1	44.5 ***********************************		********
2 电线电影显示性电视电影电影电影电影电影电影电影电影电影性电影电影电影电影电影电影电影电影电影		 System	UNADJ	LOANU	ADJ	ADJ
n		COST	ALLOC	COST	ALLOC	COST
,	ALLOC	(2000)	FACTOR	(\$000)	FACTOR	(\$000)
	INDEX		184 K S 4 S 2 S S S		#########	*****
医电池电阻电池电池 医拉克斯氏征 医克里氏征 医克里氏征 计图像 化二十二十二十二十二十二十二十二十二十二十二十二十二十二十二十二十二十二十二十						
FORECAST PERIOD COSTS		10,145	0.23793	2,414	0.22063	2,238
Commodity Related Base	•	212,600	0.22983	48,861	0.21295	45,273
Transmission Base	Ċ	43,869	0.21497	9,431	0.19809	8,690
Storage Base	ď.	276,945	0.12111	33,541	0.11045	30,587
Distribution Same	b-	499,381	0_01290	6,443	0.01290	6,445
Customer Base	m.	88,634	0.24008	21,279	0.22268	19,737
50% Adminstrative and General		(9,149)	0.10779	(986).	0.09983	(913)
Other Operating Revenue			•			
SUBTOTAL - Base (Margin)		1,122,424		120,983		112,056
SOBIOINE - BEST CHAIRMAN	,				0.11509	* (d),403)
EOR Credit	h	(12,187)	0.12424	(1,514)		(1,468)
Interutility Transportation Service	•	(6,893)	0.22983	(1,584)		(2,075)
Brokerage Fee: Procurement A&G	j	(5,298)	0.41468	(2,197)		(2,0,5)
Brokerage Fee: Core Marketing	k.	(6,389)	0.00000		0.00000	ر وري دوري
Brokerage Fee: Noncore Marketing		(123)	0.64325	(793	0.64325	(631)
Long Term Contract Revenue	٥	(2,858)	0.23793	(680)	0.22063	
Count term contract was			-		14 15	104 (00)
SUBTOTAL - Adjusted Base		1,088,676		114,929		106,400
SADIAINE Uniterate and				77 505	0.21295	37,585
Pipe Demand Charges	6:	176,496	0.21295	37,585	0.40680	977
Pipeline Demand Trueup	16	2,401	0.40680		0.19809	2,887
Ges Storage Carrying Costs	7	14,574	0.19809	2,887,	, T	795
Cas Storage Trueup	17	1,708	0.46536	795		6,067
Take-or-pay Transition Costs	1.	27,500	0.23912	6,576	0.22063	
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 Accour	1 1	50,000	0.23912	11, 956	0.22063	11,031
Gas Exploration a poveropionic reservi-	11	61,841	0.26235	16,224	0.23665	14,635
LUAF & GOU	12	4,489	0.30926	1,388	0.27509	1,235
CPUC Fee	14	1,961	0.36090	708	0.33706	661
LIRA AEG	19	728	0.00000	0	0.00000	0
ROED Trueup - Core	17	352	0.46536	164	0.46536	164
RDED Trueup - Noncore	17	(193)		(90)	0.46536	(90)
Noncore Base Cost Adjustment	20			(454)	0.44510	(454)
1990 ACAP FEU Adjustment	21	(289)		(139)	0.48004	(139)
Corporate Franchise Tax Adjustment			0.74511	362	0.72809	354
Earthquake Recovery Adjustment	, <u>, , n</u>		4.1 -2.1			
TOTAL - Forecasted Period Costs		1,452,804		199,674		187,474
TOTAL . FORECASES PER TOS COSES					. 4	
AMORTIZATION OF BALANCING ACCOUNTS					0.00000	0
Gas Core Fixed Cost	3	49,873	0.00000	0	0.39173	(1,057)
Noncore Transition Cost	9	(2,699)	0.41624	(1,123)		
Enhanced Oil Recovery	5	(2,492)	0.11369	(283		
A&S Interutility	6	(109)		(23	0.21295	
CFA Debt Service and Expense	2	(1,327)	0.34719	(461	0.00000	/152 stab 0
	3		0-00000-	n.º	0.00000	tha And O
Core TOP	1	. 0	0.23912	Ü	0.4400	2 2 2 200
NGV		(8,277	0.36090) 0.33706	(2,790)
LIRA	12		0.00000	v) >-> 0
COGEN Shortfall	-		•			77,583
TOTAL - Forecasted Acct Balances		36,075		(4,878	•	(4, 103
TOTAL TOTAL				1,820	1000	1,708
FEU	315	13,793		1,020		*******
		4 240 400	•	196,616		184,599
TOTAL - Transport Revenue Require	ement	1,502,072			Zasarini	
ALLOCATION ADJUSTMENTS		8 969	0.09775	. 9	0.0977	5 95
G-10 Allocated Employee Discount	.N ² - 1	(7,941		(5,628	3) (- 1 - 1 - 1 - 1 - 1 - 1 - 1 - 1 - 1 -	().040
cc.2 Shortfall		(/,741 • 70/4			0.2124	5 1,687
cc-2 Shortfall Allocated		8 7,941		اردوده دورون ازدوده دورون	1	- 5 DO (
ita Discount Benefits	× .	(17,400		6,23	0.3370	6 5,820
LIRA Discount Expenses	1	4 17,268				
	٠ .			199,15		186,57
TOTAL - Transport Costs	٠	1,503,641	1	-		
1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1				1000		

PACIFIC GAS AND ELECTRIC COMPANY UEG CUSTOMERS COST ALLOCATION

	ALLOC	SYSTEM COST (\$000)	ALLOC	LCANU T2OD (COO2)	ADJ ALLOC FACTOR	ADJ COST (\$000)
00 - 1 - 1 - 1 - 1 - 1 - 1 - 1 - 1 - 1 -						***********
RECAST PERIOD COSTS		40.445	0.20167	2,046	0_20667	2,097
Commodity Related Base			0.17418	37,032	0.17835	37,917
Transmission Base	•	212,600	0.10847	4,759	0.11099	4,869
Storage Base		,	0.00000	ó	0.00000	0
Distribution Base		276,945	0.00247	1,233	0_00247	
Currency Rese	ъ.			18,036		18,488
50% Adminstrative and General		88,634	0.20349	(510)	0.05709	(522
Other Operating Revenue		(9,149)	0.05577		4	
SUBTOTAL - Base (Margin)	1	,122,424		62,595		64,080
	,	(12,187)	0-07173	-(874)	0.07344	(895
EOR Credit		(6,893)	0.17418	(1,_201)/	0.17835	(1,225
Interutility Transportation Service		(5,298)	0.35148	(1,862)	.0.36694,	(1,944
Brokerage Fee: Procurement A&G		(6,389)		0	.0.00000	
Brokerage Fee: Core Marketing		(123)		(15)	0.12309	(1:
Brokerage Fee: Noncore Marketing		(2,858)	0.20167	(576)	0.20667	(59
Long Term Contract Revenue			•			
SUBTOTAL - Adjusted Base	•	1,088,676		58,067		59,40
		176,496	0.17835	31 478	0.17835	31,47
Pipe Demand Charges	16		0.34070	818	. 0.34070	
Pipeline Demand Trueup		14,574	0.11099	1.618	0.11099	1,61
Cas Storage Carrying Costs	7 17	1,708	0.26073		0.26073	44
Gas Storage Trueup	17	27,500	0.20133	5.537	.0.20667	5,68
Take-or-Pay Transition Costs	1		0.20133		0.20667	
Take-or-Pay Trucup	1	20,467	0.00000		0.00000	and the second
CFA Debt Service and Expense	2			10,066	0.20667	10,33
Gas Exploration & Development Acco	unt 1	50,000	0.20133	12,360	0.20059	12.40
LUAF & CDU	,			12,500		
CPUC Fee	12	4,489			0.00000	Alabert (N. 1977)
LIRA ALC	14	1,961			0.00000	
RDED Trueup - Core	19	728	0.00000		0.26073	
RDED Trueup - Noncore	17	` 352	0.26073		0.26073	
Noncore Base Cost Adjustment	17	(193)			0.30669	
1000 ACAP F&U Adjustment	20	(1,021)			0.26810	
Corporate Franchise Tax Adjustment	21	(289)		(11)	0.00000	والمراجع المراجع المراجع
Earthquake Recovery Adjustment	n	486	0.00000		0.0000	
TOTAL - Forecasted Period Costs		1,452,804	ر سر	124,160	and the second	126,0
AMORTIZATION OF BALANCING ACCOUNTS	1 30 4	<u>;</u>			4505	anno Luco
Cas Core Fixed Cost	3	49,873	0.00000	• • 0.,	0.00000	يوزو ۱۰ کارونو ۱۰
Noncore Transition Cost	· • • • •			(944)	0.36694	(9
Noncore (ransktor) dos	5	(2,492)	0.07172	(179)	0.0717	2, , , (1
Enhanced-Oil Recovery	6	(109)	0.17835	(19)	0_1783	5 000 / 100 C
A&S Interutility CFA Debt Service and Expense	2	(1,327)	0.00000	Ó	0.0000	
CLY DEDE 26LAICE BIN EXPERIMENT	3			Ģ	0.00000	
Core TOP		0	0.20133	0	0.2066	
, NGV	- 14	(8,277)	0.00000	.0	0.0000	
LIRA	13	1,106	0.68867	762	0.6908	27
TOTAL - Forecasted Acct Balance	· , ·	36,075	4 1 1 1 1	(382)	Car Maria 1	ζ4
w b		13,793		1,161		1.1
F8U			• , , , , , , ,	*******	N. 10 10 10 10 10	
TOTAL - Transport Revenue Requi	rement	1,502,672		124,938	•	126,8
7 95 Jan 1 97 37				15 ()	MARINGA D	M. Taribar
ALLOCATION ADJUSTMENTS		ميم `	0.05459	44	0.0545	9.
	18					(2,3
C-10 Allocated Employee Discount		ረፖ,94 1	>	دادر2)	0 2111	5 1.0
G-10 Allocated Employee Discount			V JUELL			
G-10 Allocated Employee Discourt		7,941	0.20577	.1,054. 0	0.2113	C WINDS
G-10 Atlocated Employee Discourt GC-2 Shortfall GC-2 Shortfall Atlocated		7,941 (17,268)	0		
G-10 Allocated Employee Discourt	14	7,941 (17,268	0.00000	0	0.0000	

TABLE 11

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

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

		SYSTEM.	UNADJ	LOANU	LOA	ADJ
	ALLOC		ALLOC FACTOR	COST (\$000)	FACTOR	COST (\$000)
	INDEX	(\$000)	アストリンス			
ORECAST PERIOD COSTS						
Commodity Related Base	8	10,145	0.09108	924	0.09250	
Transmission Base	•	212,600	0.08790	18,688	0::08919	18,962
Storage Base	¢.	43,869	0.07160	3,141	0.07256	3,183
Distribution Base	ď	276,945	0.02464	6,823	0.02474	6,853
Customer Base	b .	499,381	0.00301	1,502	0.00301	1,502
50% Adminstrative and General	₩ .	.58,634	0.09190	8,146	0.09335	
Other Operating Revenue	11	(9,149)	0.03466	(317)	0.03510	' (321
SUBTOTAL - Base (Margin)	. 1	,122,424		38,906`	·/ * · · ·	39,392
man manufacture	i i	(17 197)	0.04184	(510)	0.04239	(517
EOR Credit	h	(12,187)	0.08790	(606)		(615
Interutility Transportation Service	•	(5,298)		(841)		(870
Brokerage Fee: Procurement A&G	J.			(04)	0.00000	```````
Brokerage Feet Core Marketing	k.	(6,389) (123)	0.14996	` (18)	0.14996	
Brokerage Fee: Noncore Marketing Long Term Contract Revenue	į. a	(2,858)		(260)		(264
Long Term Contract Revenue	٠.	(2,050)	0107100		. X - 14 - 15 - 1	
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 Trucup	i	20,467	0.09102	1,863	0.09250	1,893
CFA Debt Service and Expense	. 2	2,628	0.00000	0	0.00000	Strain C
Gas Exploration & Development Account	_	50,000	0.09102	4,551		4,625
LUAF & GDU	11	61,841	0.09601	5,937	0.09539	and the second second
CPUC Fee	12	4,489	0.12833	576	0.12766	573
LIRA A&G	14	1,961	0.00000	0	0.00000	
	19	728	0.00000	ŏ	0.00000	Ô
RD&D Trueup - Core	17	352	0.17046	60	0.17046	- 60
ROED Trueup - Noncore	17	(193)	· ·	(33)		(33
Noncore Base Cost Adjustment	20	(1,021)		(168)		(168
1990 ACAP F&U Adjustment Corporate Franchise Tax Adjustment	21	(289)		(48)		400000048
Earthquake Recovery Adjustment	, n	486	0_15157	74	0.16313	24 - 444 <mark>79</mark>
TOTAL - Forecasted Period Costs		,452,804		69,485	which is a second	70,030
NORTIZATION OF BALANCING ACCOUNTS	.`,	i.	2.5152		Charle o	11.
Gas Core Fixed Cost	3	49,873	0.00000	0	0.00000	0
Noncore Transition Cost	9	(2,699)		(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	
CFA Debt Service and Expense	- 5	(1,327)	0.00000	0	0.00000	Smedica 0
	. 3	0	0.00000	-	0.00000	
Core TOP	1	ŏ	0.09102		0.09250	
NGV LIRA	14		0.00000	ŏ	- 17 1 1 2 T 1 N	
COGEN Shortfall	13	1,106	0.31133	344		//√342
TOTAL - Forecasted Acct Balances		36,075		(197)	*y 900	(215
FZU	· · · · ·	13,793	* * * * * *	•		©* 653
TOTAL - Transport Revenue Requirem	ent	1,502,672		69,935		70,468
LOCATION AD HICTMENTS	•	994	en and the same	119 1 1 N	province in	* 19 ² 1-2
LLOCATION ADJUSTMENTS	18	969	0.03409	33	0.03409	33
G-10 Allocated Employee Discount	DAG.	(7,941)	~~~~~	(2,313)	1820 1831	
AC-E SHOLCIACE	8	7,941	0-08379	665		
GC-2 Shortfall Allocated	. •	(17,268)	+= ~~ /	30	13 (1.424)	
LIRA Discount Benefits	14		0.00000		0.00000	-
LIRA Discount Expenses	14	17,268	V-00000	2 6 6	0.0000	-
MANAL - Wassessan Asses	20 mg - 1 	1 50% AA1		68,321	e Harris	9-68,864
TOTAL - Transport Costs		1,503,641		44696		,

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PACIFIC GAS AND ELECTRIC COMPANY WHOLESALE CUSTOMERS COST ALLOCATION

	Cara in	SYSTEM	LOANU	UNADJ 🖯	ADJ	LOA
	ALLOC	COST	ALLOC	COST	ALLOC	COST
,	INDEX		FACTOR	(\$000)	FACTOR	.,<\$000 <i>\</i> _
		*********	*=======	#6224##60V		
DRECAST PERIOD COSTS			A 0180/	192	0.01941	197
Commodity Related Base	•	10,145	0.01894		.0.01984	4,218
Transmission Base	• .	212,600	0.01938 0.02342	1,027		1,051
Storage Base		43,869	0.00000		0.00000	
Distribution Base	ď	276,945 499,381	0.00043	-	0.00043	214
Customer Base	· b	499,301	0.01006	892	0.01031	914
50% Adminstrative and General	m-	88,634			0.00582	(5)
Other Operating Revenue	, ₹ .	(9,149)	0.00000	(34)	·/	الإيوارات المحرية الا
SUBTOTAL - Base (Margin)		1,122,424		6,393	OT BET LE	6,54
			0.00753	(92)	0.00771	(9
EOR Credit	rger - h ij	(12,107)	0.0000	/1345	0.01984	
Interutility Transportation Service	ce é	(0,093)	0.01938		0.03447	(18
Brokerage Fee: Procurement ALC	.]	(5,298)	0.03302		0.00000	
Brokerage Fee: Core Marketing	rig ki	(6,389)	0.00000			
Brokerage Fee: Noncore Marketing	L	(123)	0.02134		0.02134	
-Long -Term Contract: Revenue.		(2,858)	.0.01894	· (54),	. 0.01941	· //:-
			1	* AT4	•	6,06
SUSTOTAL' - Adjusted Base		1,088,676	,		.VW 2/00001	(1),14.
Pipe Demand Charges		176,496	0.01984		0.01984	3,50
Pipeline Demand Trueup	16	2,401	0.03790	91	0.03790	34
Cas Storage Carrying Costs	7	14,574	0.02396	349		KI T Z
Gas Storage Trueup	17	ეტე 1,708	0.05629	96	0.05629	
Take-or-Pay Transition Costs	1	27,500	, 0.01891		0.01941	53
Take-or-Pay Trueup	1		0.01891	387	0.01941	39
CFA Debt Service and Expense	2	2,628	0.00000	O O	0.00000	
Gas Exploration & Development Acc			0.01891	.946	. 0.01941	97
	11	61,841	0.01877	1.161	0.01884	1,16
LUAF & GDU	12	/ /80	0.00000			
CPUC Fee	14	1,961	0.00000	0	0.00000	HQT
LIRA AEG		728.		1	0.00000	
RDED Trueup - Core			0.05629	20	0.05629	······································
RDED Trueup - Noncore	17				0.05629	
Noncore Base Cost Adjustment	17			(32)		900 H 💆
1990 ACAP FEU Adjustment	20				0.02733	
Corporate Franchise Tax Adjustmen	r 21				0.00000	
Earthquake Recovery Adjustment.	· n	400), #391574 **********		
TOTAL - Forecasted Period Costs	•) • • • =	1,452,804		12,956	axis odki	" ' 1 3 '/14
MORTIZATION OF BALANCING ACCOUNTS			A. 1777 17 11		3777 830	JA M.T
Cas Core Fixed Cost	3		0.00000	0.,	0_00000	53%
Noncore Transition Cost	9	(2,699)	0.03292		0.03447	A112 C
Enhanced-Oil Recovery	5.	(2,492)	. 0.00754	(19)	0.00754	() (286.181.14
ALS Interutility	6	(109)	0.01984	(2)	0.01984	
CFA Debt Service and Expense	2	(1,327)	0.00000	s 230 d 0 k	0.00000	of tu Stable
	*	0	0.00000	່ ` ` ` ' ' (0 ີ	. 0.00000	
Core TOP	• •	Ó	0.01891	, ۰,۰۰۰ ر ۲۰۰۰	0.01941.	
	14	(8.277)	0.00000		0.00000	المراجع والاست. المراجعة ودارة
	13	1,106	0.00000	0	0.00000	TODDEN 1
CORE SHOT CLASS	· -		No long broken	(110)	uman sam	रहार हो
TOTAL - Forecasted Acct Balance	75	30,013				
& 201 		13,793	236.47	108	11 to 5 17 1	90 m.: 30 ₀
F&U	** · · · · · · · · · · · · · · · · · ·					
TOTAL - Transport Revenue Requ	irement	1,502,672		12,954	ាស់ស្នាមស្រាមម	13,1
ALLOCATION ADJUSTMENTS		A.A	A AAFF4	5	0.00556	
G-10 Allocated Employee Discount		969		_	0.00,50	
GC-2 Shortfall		(7,941) 7,941)	0	0 01000	
GC-Z Shortfall Allocated	8	7,941	0.01933		0.01985	1
LIRA Discount Benefits		(17,268))	0	0.0000	
LIRA Discount Expenses	14	17,268	0.00000			
Petra Atanamia milatina						47 8
		1,503,641		13,113		13,3
TOTAL - Transport Costs		,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,				

So. 25 . . .

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TABLE 13

to Tali At PACIFIC GAS AND ELECTRIC COMPANY UEG/COGEN PARITY

Forecasted Period	l: Aprí	l 1, 1991	to M	erch 31, 19	92
		19 1 15		83113	and the transfer of the state o
FR LIVER COS: (444 3)					
EG IGNITER FUEL FIXED COST OGEN FIXED COST (EXCLUDING GC-2)	and a	1 (1) (1) (1) (1) (1) (1) (1) (1) (1) (1	نياز لازد. انواد ارا	4,403	
OCEN FIXED COST (EXCLUDING GC-2)	enser – septe	STATE OF STATE		65,059	The state of the s
TOTAL UEG/IGNITER FUEL/COGEN FIX	ED COS	T			\$198,015 GASC - NOT A 29 - TOWNS
		-4- - 1,91	• *		وجود ومرواه والرازية والمارات والمارات والمارات والمارات
EG SUPPLY FORECAST (Mth)		1,462	,600		Salar Carlotte Carlot
GNITER FUEL FORECAST (Mth)		-14	,450		ుగాన్ ఉన్నారు. ముగ్రామ్ కుట్టుకున్నారు.
LICE VOLUMES CHARA	· .	43,350	, ,	1,477,050	in the second
UEG VOLUMES (Mth)		1. 1. 1. 1. 1.		,,,,,,,,,,	The transfer of the state of the second
OGEN SUPPLY FORECAST		696	,000		the start of the start of the
¢-2		(66 (35	,000)		
OJAVE LONG TERM CONTRACT		(35	,000)		7 7 7 8 66 G G G C C C C C C C C C C C C C C C
AINAN HARRA BARGN NALIMER				595,350	
DNADJUZIED COGEN VOCOMES					ان در
COURT DISCOUNT AND PACTOR		1 44			والمراجع والمستوان والمستعمرات
COGEN VOLUMES (EXCLUDING GC-2)		, e j		589,000	وعاليهم وعاهاته أنجا المعقود الشياه الماساله والاراكال
	1.0				the term of the second of the
TOTAL UEG/IGNITER FUEL/COGEN'V	OLUMES	. Saire.	,		2,066,000/0632/60 ethe ,inc.
UEG/COGEN AVERAGE RATE (\$/th)	Section of the second			7.90 J. (1987) J. (19 .00.09435)/T-Rod
British Salaka Salak	,				narakkukakuroba poosaan) - "" '
					pure of the regiment of the property
OGEN FIXED COST RESPONSIBILITY		of Sant	ti		and the second regarded the
SUPPLY FORECAST (Mth)	11.0	589	,397		Spring of the property of the second
UEG/IGNITER FUEL/COGEN AVE RATE	(\$/th)	0.0	9584		Committee and a substitution of the substituti
	· 4.			#E4 /ED:	Madalis of Sameral Sameras Sameras Sameras (Sameras)
GC-2 CONTRACT REVENUE				3,805	
GG-2 GON INNOT KEYENGE		Sec 10	٠.		100 - AU.
TOTAL COGEN FIXED COST RESPO	NSIBIL	ITY 🦙			\$60,257 (-1.00%)
$\frac{\partial f_{ij}}{\partial x_{ij}} = \frac{\partial f_{ij}}{\partial x_{ij}} + \partial $	41.0	rojej _e i	14.7		She Av.
	-				
CO TIVER COST RECRAICION TO THE	EC.	· .			(DAD 1), while it was not to North one was Cost subjection
EG FIXED COST RESPONSIBILITY (G-U	EU)		1.1		1980 in 1980 and 1980 and 1980
UEG/IGNITER FUEL/COGEN FIXED COS		V. 🚣	117	\$198,015	graduated and animal and animal and
COGEN FIXED COST RESPONSIBILITY	er e	15.60	71	(56,452)	had the country of the first terms of the second of the party of the country of t
IGNITER FUEL FIXED COST		5.3 CH		(4,403)	
**		opposition (•		on. All Compagency - BATOT
TOTAL UEG FIXED COST RESPONSIB	ILITY			1 × 24 h	\$137,159 Nacidity Calabar dia 2001/2001 and that
UEG AVERAGE RATE (\$/TH)		. 12 VA			#401 DOL0937802 365
1. The second of	9.5 9	$S(\mathfrak{s}, \mathfrak{S})$	4		AUSTROPH PRODUCTION COLL
* 4 * * 4 * * * * * * * * * * * * * * *	alt A		6		alia demondo ^e 179 Com Continola de 2000 - 11 - 1
EG/IGNITER FUEL FIXED COST RESPON	? PIRIFI		:		una una cambian ani ani Domini II
UEG/IGNITER FUEL/COGEN FIXED COS	तं.े ः			\$198,015	VQW
COGEN FIXED COST RESPONSIBILITY	Mark Line	5 0,%)		(56,452)	A41.
and the fifth program of the state of the st	V	40 ° 1		•••••	Eyra Mithian (Eil an Eulop)
UEG/IGNITER FUEL FIXED COST RESP	ONSIBI	LITY			\$141,562
				The talk.	1907 (1907) - 1907 (1907) 1907 (1907) 0.09584
UEG/IGNITER FUEL AVE RATE (\$/TH)	'n	$\phi_{i_{1},i_{2}}^{*}(x)$			0.073 04 547

"#3,22111"

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TABLE 14

PACIFIC GAS AND ELECTRIC COMPANY GC-2 CONTRACT SHORTFALL

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

PARTICULAR TO PARTY PROPERTY AND	1.5			
INDUSTRIAL GC-2 SUPPLIES (Mth)	•			91,170
TRANSPORT COST BEFORE ALLOC ADJ	(000'\$)		\$184,591	19.00
STEAM HEAT (Mth)		10,860		* **
NONCORE INTERDEPARTMENTAL		1,030		
INDUSTRIAL GC-2		91,170		
INDUSTRIAL G-IND	1,383,430			
UEG-SCE	239,000	The State of the		
		of the same of the same	n n a latin in	
	1,622,430		والمعارض والمراور	
INDUSTRIAL DISCOUNT ADJ	0.89882			
DISCOUNT ADJUSTED INDUSTRIAL		1,458,273		
	••		on the second of	
TOTAL DISC ADJ INDUSTRIAL & INDUS	STRIAL GC-2 (Mth)		1,561,333	
STANDARD INDUSTRIAL RATE BEFORE A	ALLOC ADJ (\$/th)	•		0.11823
ALLOCATED INDUSTRIAL GC-2 FIXED (COST RESPONSITILITY	r (000's)		\$10,779
INDUSTRIAL GC-2 CONTRACT REVENUE				•
	and the second of the second	gista ma	A STATE OF THE STA	******
INDUSTRIAL GC-2 REVENUE SHORTFALI				\$5,629

COGEN GC-2 SUPPLIES (Mth)				65,650
			\$126,821 .	65,650
COGEN GC-2 SUPPLIES (Mth)	(2,000) ra		\$126,821. 70,468	65,650
COGEN GC-2 SUPPLIES (Mth) JEG TRANSPORT COST BEFORE ALLOC /	(2,000) ra	1,462,600	· -	65,650
COGEN GC-2 SUPPLIES (Mth) JEG TRANSPORT COST BEFORE ALLOC A COGEN TRANSPORT COST BEFORE ALLOC	(2,000) ra	1,462,600 65,650	· -	65,650
COGEN GC-2 SUPPLIES (Mth) JEG TRANSPORT COST BEFORE ALLOC COGEN TRANSPORT COST BEFORE ALLOC JEG-(Mth)	(2,000) ra		· -	65,650
COGEN GC-2 SUPPLIES (Mth) UEG TRANSPORT COST BEFORE ALLOC COGEN TRANSPORT COST BEFORE ALLOC UEG- (Mth) COGEN GC-2	(S,000) rdw		· -	65,650
COGEN GC-2 SUPPLIES (Mth) JEG TRANSPORT COST BEFORE ALLOC COGEN TRANSPORT COST BEFORE ALLOC JEG- (Mth) COGEN GC-2 COGEN G-COG	629,880		· -	65,650
COGEN GC-2 SUPPLIES (Mth) JEG TRANSPORT COST BEFORE ALLOC COGEN TRANSPORT COST BEFORE ALLOC JEG- (Mth) COGEN GC-2 COGEN G-COG	629,880		· -	65,650
COGEN GC-2 SUPPLIES (Mth) JEG TRANSPORT COST BEFORE ALLOC COGEN TRANSPORT COST BEFORE ALLOC JEG- (Mth) COGEN GC-2 COGEN G-COG	ADJ (000'S) ADJ (000'S) 629,880 (35,000) 594,880		· -	65,650
COGEN GC-2 SUPPLIES (Mth) JEG TRANSPORT COST BEFORE ALLOC A COGEN TRANSPORT COST BEFORE ALLOC JEG (Mth) COGEN GC-2 COGEN G-COG MOJAVE LONG TERM CONTRACT COGEN DISCOUNT ADJUSTMENT	ADJ (000'S) 629,880 (35,000)	65,650	· -	65,650
COGEN GC-2 SUPPLIES (Mth) JEG TRANSPORT COST BEFORE ALLOC A COGEN TRANSPORT COST BEFORE ALLOC JEG- (Mth) COGEN GC-2 COGEN G-COG MOJAVE LONG TERM CONTRACT	ADJ (000'S) ADJ (000'S) 629,880 (35,000) 594,880		· -	65,650
COGEN GC-2 SUPPLIES (Mth) JEG TRANSPORT COST BEFORE ALLOC / COGEN TRANSPORT COST BEFORE ALLOC / JEG (Mth) COGEN GC-2 COGEN G-COG MOJAVE LONG TERM CONTRACT COGEN DISCOUNT ADJUSTMENT DISCOUNT ADJUSTED COGEN	429,880 (35,000) 594,880 0.99000	65,650	70,468	65,650
COGEN GC-2 SUPPLIES (Mth) JEG TRANSPORT COST BEFORE ALLOC A COGEN TRANSPORT COST BEFORE ALLOC JEG (Mth) COGEN GC-2 COGEN G-COG MOJAVE LONG TERM CONTRACT COGEN DISCOUNT ADJUSTMENT	429,880 (35,000) 594,880 0.99000	65,650	· -	65,650
COGEN GC-2 SUPPLIES (Mth) JEG TRANSPORT COST BEFORE ALLOC A COGEN TRANSPORT COST BEFORE ALLOC JEG- (Mth) COGEN GC-2 COGEN G-COG MOJAVE LONG TERM CONTRACT COGEN DISCOUNT ADJUSTMENT DISCOUNT ADJUSTED COGEN COTAL DISC ADJ UEG, COGEN & COGEN	ADJ (000'S) 629,880 (35,000) 594,880 0.99000	65,650	70,468	65,650
COGEN GC-2 SUPPLIES (Mth) JEG TRANSPORT COST BEFORE ALLOC / COGEN TRANSPORT COST BEFORE ALLOC / JEG (Mth) COGEN GC-2 COGEN G-COG MOJAVE LONG TERM CONTRACT COGEN DISCOUNT ADJUSTMENT DISCOUNT ADJUSTED COGEN	ADJ (000'S) 629,880 (35,000) 594,880 0.99000	65,650	70,468	
COGEN GC-2 SUPPLIES (Mth) JEG TRANSPORT COST BEFORE ALLOC A COGEN TRANSPORT COST BEFORE ALLOC JEG- (Mth) COGEN GC-2 COGEN G-COG MOJAVE LONG TERM CONTRACT COGEN DISCOUNT ADJUSTMENT DISCOUNT ADJUSTED COGEN COTAL DISC ADJ UEG, COGEN & COGEN	ADJ (000'S) ADJ (000'S) 629,880 (35,000) 594,880 0.99000 EN GC-2 (Mth)	65,650 588,931	70,468	0.09318
COGEN GC-2 SUPPLIES (Mth) JEG TRANSPORT COST BEFORE ALLOC A COGEN TRANSPORT COST BEFORE ALLOC JEG- (Mth) COGEN GC-2 COGEN G-COG MOJAVE LONG TERM CONTRACT COGEN DISCOUNT ADJUSTMENT DISCOUNT ADJUSTED COGEN FOTAL DISC ADJ UEG, COGEN & COGE STANDARD UEG/COGEN RATE BEFORE AL	ADJ (000'S) ADJ (000'S) 629,880 (35,000) 594,880 0.99000 EN GC-2 (Mth)	65,650 588,931	70,468	0.09318
COGEN GC-2 SUPPLIES (Mth) JEG TRANSPORT COST BEFORE ALLOC A COGEN TRANSPORT COST BEFORE ALLOC JEG- (Mth) COGEN GC-2 COGEN G-COG MOJAVE LONG TERM CONTRACT COGEN DISCOUNT ADJUSTMENT DISCOUNT ADJUSTED COGEN FOTAL DISC ADJ UEG, COGEN & COGE STANDARD UEG/COGEN RATE BEFORE AL ALLOCATED COGEN GC-2 FIXED COST R	ADJ (000'S) ADJ (000'S) 629,880 (35,000) 594,880 0.99000 EN GC-2 (Mth)	65,650 588,931	70,468	0.09318
COGEN GC-2 SUPPLIES (Mth) JEG TRANSPORT COST BEFORE ALLOC A COGEN TRANSPORT COST BEFORE ALLOC JEG- (Mth) COGEN GC-2 COGEN G-COG MOJAVE LONG TERM CONTRACT COGEN DISCOUNT ADJUSTMENT DISCOUNT ADJUSTED COGEN FOTAL DISC ADJ UEG, COGEN & COGE STANDARD UEG/COGEN RATE BEFORE AL ALLOCATED COGEN GC-2 FIXED COST R	ADJ (000'S) ADJ (000'S) 629,880 (35,000) 594,880 0.99000 EN GC-2 (Mth)	65,650 588,931	70,468	

TABLE 15

PACIFIC GAS AND ELECTRIC COMPANY ADOPTED DISCOUNT FACTORS

RATE SCHEDULE		DISCOUNT *
**************************************	- 14 14 16 16 16 16 16 16 16 16 16 16 16 16 16	e Almine vice with decorpt Geod category Mil
G-IND (excluding SC	E Cool Water)	98 % - 2002-2004-000-2003-2003-2003-2003-2003-2
G-P2B	2.2876) 26852	97% - Skinning aller kommer.
G-COG		99%
n na la	$(\tau) = \frac{1}{2} \frac{1}{2} \left(\frac{1}{2} \left(\frac{1}{2} \right) \right) = \frac{1}{2} \frac{1}{2} \left(\frac{1}{2} \left(\frac{1}{2} \right) \right)$	rmung, mila ususmabuluk baharan alaktat 1971 — <mark>Alak Alak Maria</mark> 913a — N. 11, 1913a — Alak Maria Wakasa Maria
* Per negotiated s		אנת <mark>מסאד</mark> ות או אפני בארא או מסיין אין איני וביינאר הניסים או מסאד וווידע אלו ובל איניאר מיין או עניין

Light Committee and the committee of the

1.25 ्रक्षा राष्ट्रक स्थापन क्षेत्र क्षा क्षा क्षा क्षा क्षा क्षा का विकास का क्षा का कि THE KINDS OF THE CONTRACT TO SECOND STOP TO A AND THE SECOND SECO CONTRACTOR CONTRACTOR (CONTRACTOR) . . . CALMS DOD A Commence $\mathcal{Q}_{\mathcal{A}} = \mathcal{Q}_{\mathcal{A}}$ 5-20 K.WUS 00004 G-000 1200 TOTAL PRODUCTION OF STREET Sugar 1000000 COMEN DINCOUNT ADVICEDMEN 1.5 THURSD SUNFIGURE PROSPECTS TOTAL DISC ADA ULQ, COULN I CLALA COAD OMESS THE CONTROL OF THE STATE OF THE CONTROL OF THE CONT THE CONTRACTOR OF THE SECOND TO THE CONTRACT OF SECOND PROPERTY OF THE CONTRACTOR OF FIRST NEW TOWNSIAS SHIPS HIPSON 44 + 4 - 15 m 5 m - 1 - 15 M - JUANTROKY GOKOVON SHOW MODOC

TABLE 164 45

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 (MTH/CUST) (\$/TH) (M\$)	FORECAST REVENUES USING RATES EFFECTIVE 4/1/91 (MTH/CUST) (\$/TH) (MS)	ADOPTED CHANGE (\$/TH) (%)
(A)	(B) (C) (D)	(E) (F) (F) (G);	(I) (H)
\ ^\	(0)	The second of the man consider the	100 CAY
RES. NON-LIRA	10 miles (10 miles 10	the entropy of the state of the	
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)	55.0 ×
Company Non-1704	1,973,982 0.58157 1,148,013	1,973,982 0.58840 1,161,496	0.00683 1.2
Subtotal Non-LIRA	1,973,982 0.58157 1,148,013	7,475,782 0.38640 1,101,476 PM	0.00683 1.2
RES. LIRA	The second of the second of the second	The term of the control of the contr	V 12, 14
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
TOTAL RESIDENCIAL (1)			**************
SCHEDULE G-NR1 (2)			
Customer Charge	198,232 12.11 /MO 28,806	198,232 12.06 /HO 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	744 750 0 44750 /70 /74	7// 750 0 /0/50 //7 5/0	0.00000 44.53
iotal G-NKI	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)
OLDI Q-NZ	176,067 017607 17,706	172,047 0.30072 17,307	(0.01377) (2.0)
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)
marine de comp	/ 400 A 500//	/ 40/ A AN/A	44 444/6
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	25 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 /NO 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
Your Compact 1 275	022 046 6 K0746 KE4 677	022 014 A SETTE E/2 AT	70 000%N -4 1
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 168 , :

PACIFIC GAS AND ELECTRIC COMPANY FOOTHOTES TO CORE RATES AND REVENUES

				Fore	cast Period:	: April 1, 19	91 to March	31, 1992	
						, www. 25442 2544		4.5	
-		· · · · · · · · · · · · · · · · · · ·		1		**		2.4	2.1 a 1 - 2 2 - 1
	(1)	Adjusted for	6-10	SALES	4,173 Mth	l e	**********************		
	(2)	Applicable to	o P1,	PZA and	PZBcommerc	ial customers therms sold at	. With.use of	fewer than 5 27224 no	C Thedm
		Includes int	erdepa	remental	constructi	on clearing a	nd other ope	rating sale	S. Augusta (
	(3)	April through	h Octo	ber					n de San de Bergilde de San de S La companya de San d
	(4)	November thr	ough M	larch.			1.4. 44. 4	and the state of	
	(5)	Applicable to	O PI A	na pza c charme s	ommercial c	ustomers with	use of 20,0 5 23224 per	uu therma p	The state of the s
	(6)	Applicable to active month	o PT a	ind P2A c 3 schedu	ommercial c le is a tra	ustomers with insportation-o	use of 20,8 nly schedule	100 therms p	Property of the State of the St
		may contract a third-part				nt, noncore p			
	(7)	Volumes, rate	es, an	d revenu	es for NGV-	1 and NGV-2 a	re shown for	illustrati	ve (as a second of the second
•		purposes only				any calculat			
	. · · · ,	rates.		1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1	, rec	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1		1 1 W	State of Sandara State
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	11.25		s -1	, ** : * . T		8 NOT 20 1911 P		and the second of the	104 5075 177

TABLE 17A

PACIFIC GAS AND ELECTRIC COMPANY NONCORE TRANSPORT RATES AND REVENUES

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

C. ACC AT COURSE	FORECAST REVENUES USING PRESEN RATES EFFECTIVE 1/1/91 (MTH/CUST) (\$/TH) (M\$)				ST REVEN	ADOPTED CHANGE		
CLASS OF SERVICE					/ \~/!!) (MS)	\2/10/ RANGESSESS	\^/ WERREFF
(A)	(B)	(C)	(0)	(E)	(F)	(C)	/ ⟨H⟩ /	2.(1)
G-P2B (1)(15)	1					ith survive participa	1. 1. A. W.	101
Customer Charge Demand Charge 1 (3) Demand Charge 2 (4)	165,931	183.15 0.05729		165,931	206.83 0.04953		23.68-/M (0.00776)	
Summer (5)	133,359	0.01611		133,358	0.01401		(0.00210)	((13.1)
Winter (6)	97,526	0.02774		97,525	0.02286		(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)	i				10020	A State of the Sta		
Customer Charge	698	782.62		698		/MO: 4,730	· (218-14)/M	
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		17,664	1,064,767	0.01696		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)
			100.000	1 (70 704	A '40Y/A		40.007001	44.0
G-IND - Std. Rate Plum GC-2	1,469,429	0.13128	192,908 5,150	1,470,226	0.12340	181,422 5,150	(0.00789)	(6.0)
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	j 1	77,562	/MO 931	(280)M\$	(23.1)
Demand Charge (9)	ļ		107,903	ļ		96,508	(11,395)MS	(10.6)
Volumetric Charge	2/2 477	0.0//74	45 440	220 501	0 05300	1/ 001	40 043473	410 EX
Tier I (10) Tier II (11)	242,137	0.06471	15,669 33,770	270,581	0.05208	14,091 25,636	(0.01263) (0.00616)	(19.5) (22.3)
116, 17 (11)	1,220,400	0102101		1,172,017	0.02151	25,000		
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	0.10710	3,805	65,650	0.07,00	3,805	(1,000)	(/
		•••••			•••••	******		*****
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		450,462	3,848,473		405,880	(0.01161)	(9.9)
			•••••					
WHOLESALE (12) Demand Charge (9)	1		9,495	İ		11,501	2,006 MS	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		461,784	3,985,863		419,168	(0.01071)	(9.2)
			20000000000			******	****	

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TABLE 178

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

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

(3) (4)	Also includes Based on a 12 Based on a se	: interdepa 2-month mov pasonal pea : in the sa	ring averag sk month ra ume season	in the previ	e is applie	d to the his	ther of the	Current month's use or use
ය) (6)	April through	ough March	_	resent rever	nue is calcu	lares baces	on a weigh	ted average volumetric rate
(7)	Applied to ci	2-04201/th	to account	for those C	- IND CUBTOR	ers paying I	no CPUC fee	
(8)	Applies to Pi	CEE power !	lant nonce	orional to 4	ocecnisted #	onthiv volu	ne.	April 12 Company of
(10	- 	78 <i>66</i> 65 067	mantn+ ≀r	ie biendir i		the curren	c ther I vo	orumes To the Control of the Appendix of the
	rather than '	the tier 4. Il volumes	in excess	of tief I.				en e
(12)	Currently so	nedule G-W	lT	. ·		v 54.4.5.		
(74) (75)	The volumetr This occurs estimating t	ic billing because a ne require average st rion class	determinar portion of discount andard rate es are the	SCE's Load The requires differ by same for both	is priced at red discount \$,00788 th present a	PGSE's sta	noard G-INI nt between	present rates/column. atos and Proposed Rates. brate for purposes of present and proposed rates determinants for P20; because the same level of
							•	\ \ \ \ \ \ \ \ \ \ \ \ \ \ \ \ \ \ \
					- 1 - 1 × 7 · 1	e e e e e e e e e e e e e e e e e e e	15	
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	e	April 1995 April 1995		N. 1980 C.		15 (450), d. 1 15 (50) (1), d. 1	Company of the Compan	1275 2 3 447 1275 2 3 447
				of Char	ranga Marana Marana Marana	TATES AND DE	rangeria. Majaran	attended which
	0 	* . * *	1. (0.)	V. J. P.		TSTANCE C CARTERIO	rangeria. Majaran	erte de viert Geralde (1888)
· .		A Comment of the Comm	n kirki. Maraja		Andrews	77 15, 1 - 1 (M/70 10)	rangeria. Majaran	CONTRACTOR SERVICES
		200 (100 miles) 200 (100 miles) 200 (100 miles) 200 (100 miles)	1. .	Silver Si	1000, 200 1000, 200 1000, 200	757.15, 4 - 1 0567.20 0567.20 0567.20 0567.20		6.773 10 HAZ 10 HAZ
		644, V. 651, V. 701, V	1. (40.4) 1. (40.4) 1. (40.4)		AT (AT AT A	757 13, 4 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1		# 10 miles
		3.00 (1.00 (1. (40.4) 1. (40.4) 1. (40.4)	Single Si	And Comments of the Comments o	757 13, 4 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1		COLOR DE LA COLOR
		2.000 (2.	10 40 m		And Comments of the Comments o	050 13, 4 4 4 4 4 4 4 4 4 4 4 4 4 4 4 4 4 4 4		# 10 miles
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		A Control of the Cont	ALVANIAN AND AND AND AND AND AND AND AND AND A		And Comments of the Comment of the C	0.50.00		COTA IL WILLIAM COTA DA NO CARA COTA DA NO CARA COTA DA NA CARA COTA D

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

Same Bridge

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 CONTROL OF THE CONTROL RESIDENCE AT RECEIVED AND THE CONTROL OF THE CONTROL O

ROGER J. PETERS MARK R. HUFFMAN BARBARA S. BENSON

Attorneys for PACIFIC GAS AND ELECTRIC COMPANY Post Office Box 7442 77 Beale Street San Francisco, California 94120 Telephone: (415) 972-7497

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STIPULATION

BETWEEN

PACIFIC GAS AND ELECTRIC COMPANY
SION OF RATEPAYER ADVOCATES THE 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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> المحرفي يعلن المعلم منظم المسترات المعرف المحرف المسترات المعرف المحرف المعرف المحرف المعرف المحرف المعرف المع المحرفة المعطم المعرف المعرف المحرف المحرف المحرف المحرف المعرف المحرف المعرف المحرف المحرف المحرف المحرف المع MARK BY HERVEY RESERVE OF SPICES

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Page 3
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.

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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

APPENDIX D
Page 4

800,080 WYN - 1990-00-1994A

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

The period of t

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.

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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. 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

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.

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Parties recommend that, with the exception of the issues not addressed by this Stipulation, listed in Section 4, 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. in di baaanyna Sta

ారుకుండి కాండ్ కాండా చేస్తారు. సామాల ప్రాప్థికి జిల్లా కాండ్ కోడికి కాండ్ కో

B. Economic and Oil Price Inputs . 1.11年 . 開作版で 1.17**20**5 (準 1962<mark>間</mark>

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 ANTOO BUILDING ALACKE (MELICE) 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 the control العديدة والمراجع والمدينة المراجع المر والمستخدم المراجع المر expected to be high enough to require only a minimal level of discounting. The state of th ರಾಜ್ಯ ಎಂದು ಸ್ವಾಪ್ ಕರ್ಷಕ್ಕೆ ಸ್ವಾಪ್ ಕ್ರಾಪ್ ಕ್ರಾಪ್ ಕ್ರಾಪ್ ಸ್ವಾಪ್ ಸ್ವಾಪ್ ಕ್ರಾಪ್ ಸ್ವಪ್ತಿಕ್ಕೆ ಸ್ವಾಪ್ ಸ್ವಪ್ತಿಕ್ಕೆ ಪ್ರಶಿ ్రాములో కార్యాలు కార కార్యాలు కా

ರ್ಜ್ಯಾಗಿ ಕ್ರಾಂತ್ರ ಗಾರ್ ನಿಜನ್ ಸ್ಟರ್ ಅಂತ್ರಕ್ಕುವಲ್ಲಿ ಇದ್ದಾರ್ ಚಿಂದ ಕ್ರಾಂತ್ರಕ್ಕಾರ ಗಾರ್

ముంది ఇంటాలో ఎంటి మేకా ఉంది. ఎంటి ఎంటి ప్రభావం ఇచ్చి అది ఎంటికో ఎంటి సిన్ని **ప్రస్తాన్ని మెద్దికో అంది అన్ని చె**ద్దికి

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APPENDIX D

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C. Gas Throughput Forecast Communication of the control of

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

్రా కా కా ఎం. ఎం. ఉంది. కామార్లు కామానికి మంటా మేకానుకుండా ఉంది.

The Parties recommend a forecast of \$2.23 perdecatherm for the core portfolio WACOG, and a forecast of \$2.52 per decatherm for the noncore portfolio WACOG. These

ు గార్జు కుర్మం కొట్టుడు. అక్కువాలు ఉంది. మంటు మరుగ్రామాన్నా అనికాయాలు మండుకుండి.

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Page 8 values do not include franchise fees and uncollectible accounts expense or brokerage fees.

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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

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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

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Page 9

account. The allocation between classes of the balance in this balancing account will be decided in PG&E's next costend allocation proceeding.

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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

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APPENDIX D

FOR 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 PGEE's will disting 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. Market Response and the Discount Adjustment Constitution Methodology

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%.

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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. 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

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.

APPENDIX D

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

G- Cost Allocation

The Parties recommend that the Commission adopt the cost allocation methods presented by PGGE 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.

The throughput forecasts presented in Tables 4 and 5 contracts:

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GENERAL TERMS - Slev can light of lines

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

APPENDIX D

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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 results of the consumer of the construction of this stipulation. The results of the consumer of the construction of the constructi

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ాడు - ద్వాహ్మస్తులో కొర్పాలు కొడ్డారు. ప్రాపత్తున్న అయ్యకార్ కుట్టు అయిని మండి అంది. మామార్గాలు కార్మాలు కొన్నారు. కొట్టుకోరు కార్మాలు కొడ్డి అయిని అయిని అయిని మండి అయిని మండి అయిని అందిని

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APPENDIX p

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

Pacific Gas and Electric Company
By: MARK R. HUEFMAN Date
Division of Ratepayer Advocates
A STATE OF THE STA
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By: Wh. J. Work Date 11/27/90
WONG
City of Palo Alto
City of Palo Alto
By: /ful/~ lel 11/2 7/91
ARIEL P. CALONNE
Canadian Producer Group
By: John W. JIMISON MRH Date 11/27/90
JOHN W. JIMISON NRH
The second of th
Southern California Edison Company
By Contraction of the Contractio
By Date 1/27/90
ANNETTE GILLIAM
Toward Utility Rate Normalization
By: Mudul f. Haris Date 11/27/90
MICHEL P. FLORIO.

The state of the s

	O29 /ALJ/K_H/jac table 1 APPENDIX D PACIFIC GAS AND ELECTRIC COMPANY REVENUE REQUIREMENT SUMMARY	11/27/1990	6 5,
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PROCU	REMENT REVENUE REQUIREMENT \$(000)	Maria Cara	
	Forecasted Gas Portfolio Costs:		
1	Core (includes Core-elect) and control of a st. 388,11	7	1 1
2	Noncore \$73.21		5
-	***********	- -	-
3	Total Commodity Costs	\$1,461.329	2
4	Brokerage Fees, and the management of the participation of the participa	\$11,124	Ă
5	Core Purchased Gas Account Balance	\$10,149	5
Ĭ	Franchise Fees and Uncollectible Accounts Expense	113.270	
0	Ligitalities Less and districtions withoute tybense	113.2/0	6
7	Total Procurement Revenue Requirement	\$1,495,871	7
<i>'</i> .	Total Procuredent Revenue Regulerent		
9	Tess: Procurement Revenues at Present Rates	\$1,590,007	8
9 TRANS	Change in Procurement Revenue Requirement	(\$94,136)	Q
	Forecast Period Costs:		
10	Base Amount \$1,070,78		10
11	EOR Credit		11
12	Interutality Credit Chara . Command 1 16.89		12
13	Broxerage Fee Credit (\$11,22	4)	13
14	Long-Term Contract Credit : (32,92	L)	14
15	ROAD Trueup amus amus abit 6 - 6 Nerios)	15
10	Pipeline Demand Charges \$176,49		16
17	Pipeline Demand Trueup		17
18	Carrying Cost on Gas in Storage \$14.57		18
19	Storage Carrying Cost Trueup 894		19
20	Take-or-Pay Transitiom Costs 3 427,50		20
21	Take-or-Pay Trueup \$20,85		21
22	CFA Debt Service and Expenses 3 1 200 22 250 10 10 10 12 12 15	, 1	22
23	GEDA \$50,00		27
24	LUAF # 60U Gas \$61.84		25 24
			25
25	CPUC Fee Expense		
25	1,96	•	26
27	Total Forecast Period Costs	\$1.405,309	27
-	Aportization of Ralancino Account Ralances:	,	
28	Core Gas Fixed Cost: Account 1 00000000000000000000000000000000000)	28
2 6	Noncore Transition Cost Account (\$11,10		29
	Enhanced Oil Recovery Account (\$2,77%		30
22 21 20	A&S Interutility Palancing Account (\$30	Ý	31
70	A&S Interutility Palancing Account CFA Debt Service and Expense Core T-O-P Balancing Account N6V Account	•	32 32
44	Toler Tales Raises Anna Anna Maria M	•	32
33 34	CORE ITUTE DETENCTED MECOUNT	,	34 34
-	TO ACCOUNT WITH THE PARTY OF TH	, \	
35	LIRA Account Balance (\$3,598 CoGen Shortfall Account Balance	 	35
26	Cosen Shorttall. Accountryalance with the second of the se	r •	36
37	Total Forerasted Account Balances	471,500	37
38	Connection Constant Incollectible Accounts Events	\$4,115	26
**		**********	-
39	Total Transportation Revenue Requirement	\$1,500,927	3 0
	точна подраговаров пателия проможения Стиму Техниний верой од Органия ве Органия Озели	\$1,449,091	40
40	Less: Transportation Revenues at Present Rates	**********	79
41	Change in Transportation Revenue Requirement	\$51,836	41
· -	कारकारकृष कार १६ के स्वाह्मका कावकावार १९क रकारका राज्याकार कारणाव । (क) हो हुई		-
	Total Change in Revenue Requirement	(\$42,500)	42
42	intal Lazade in Revenie Mediliresent		

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

CLASS OF SERVICE	FORECAST REVE RATES EF Adj.B(LL.Det.	FECTIVE 4/19			ST REVENUES EFFECTIVE		CHANGE IN STANDARD RATES	INE .
(A)	(B) (MTH/CUST #)	(6)	(0) (M\$)	(B) (W TRUDYHTH)	(F) (S/TH)-	(G) (M\$)	(H) (T) (X) (X)	TO S
RES. NON-LIRA Tier I (Baseline) Tier II	1,497,668 476,314	.48950	733,108 385,662	1,497,668 476,314	-51767	775,298 399,080	.02817 5.8 -02817 3.5	γ(1) - 250 E - 1 200
GS,GT Adjustment			-4,394	227.5		-4,394	201 to \$ 80 to 0	
Subtotal Non-LIRA	1,973,982	-56453	1,114,376	1,973,982	- 59270	1,169,984	1_028176.000 5.0 1 2004 1 0 0 0 0 0 0 0 0	4
RCS. LIRA Tier I (Baseline) Tier II	144,776	.41139 .68355	59,559 33,856	144,776 49,529	_43698 _70913	63,264 35,122	.02559 6.2 .02558 3.7	500 00001 6
Subtotal LIRA	194,305	.48076	93,415	194,305	.50635	98,386	.02558-05.3	195 3
Total Residential (1)	2,168,287	255703	1,207,791	2,168,287	.58496	1,268,370	102704 - 20 AR5101	र ा 8 में
SCHEDULE G-NR1 (2) Customer Charge Summer Rate (3) Winter Rate (4)	198,232 307,820 458,930	.47358	27,046 145,777 293,412	198,232 307,820 458,930	11.40/MO .47441 .64045	27,117 146,033 293,922	.03/MO .30 .00083 .2 .00111 .2	10 11 11 12 12 12 12
Total G-NRT	766,750	-60807	466,236	766,750	.60916	467,072	.00109 .2	12
CHEDULE G-MR2 (5) Customer Charge Summer Rate (3) Winter Rate (4)	455 60,639 91,388	.42599	709 25,832 52,556	455 60,639 91,388	131_70/MO _41913 _56583	718 25,416 51,710	1.86/M0 / 1.4 00686 - 1.6 00926 -1.6	314 ×11 5 5
Total G-NR2	152,027	-52028	79,097	152,027	.51204	77,844	00824 -1.6	736∀ 16
CHEDULE G-NR3 (6) Customer Charge Summer Rate (3) Winter Rate (4)	6.00 1,651 2,483	129.84/HO .18143 .33053	9 300 821	6 1,651 2,483	131.70/MQ .18728 .33398	309 829	1.86/M0 11.4 .00585 3.2 .00345 12013	17 18 19:01/34/02/20/20/
Total G-NR3	4,134	.27525	1,130 periode	. 4,134	.27769	1,148	i	9 4 300 44 14
CHEDULE G-NGV1 (7) Customer Charge Volumetric Rate	6.25 .28	8.10/MO .45719	13	6,25	11.33/HO .54303	15.5 Ayd	3.23/MO 39.9 .08584 18.8	21
Total G-NGV1	28	.47889	13 ₀	28	.57338	16	.09449 19.700	23 (bas 500)
IMEDULE G-MGV2 (7) Customer Charge Volumetric Rate	35.00 523	8.10/MO -57328	300	35.00 523	11.33/MO .65913	5 345	3-23/M0-, 39.9-5 -08585 _{(200.0} 7515-0-26	(51) Duarist (24 90 (25 10)
Total G-NGV2	523	-57978	303		.68948	349	.10969, ,,,,,,,, 18_9	
stat Commercial (7)	922,911	. 59211′	546,462	922,911	.59168***	546,064	000431(2)	27 (4C) NOV JA
ITAL CORE (7)	3,091,198	-56750 1	.754,253-	3,091,198	-58697	1,814,434	17.01947 3.41g	(15,000 15 15 15 15 15 15 15 15 15 15 15 15 15

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

NE NONCORE . CUSTOMER CLASS	FORECAST REVER RATES EFF Adj.Bill.Det.	HUES USING P FECTIVE 4/19 Rate			ST REVENUES (EFFECTIVE 4/ Rate		CHANGE STANDARD	IN (COANT Line was seen to No.
ω.	(B) (MTH/GUST #)	(R1/S)	(D)	(E) (MTH/CUST #)	(F) (S/TH)	(G) (MS)	(H) (S/TH)	(1) (X)	
G-P28 (1)(15)			w **				1000		~
Customer Charge	190	171'-80/MO	392	190	195.40/HQ	446	25.60/MC	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)					04/00		plocation.		
- Summer (5) - Winter (6)	133,359 97,526	.01522 .02621	2,030 2,556	133,358 97,525	.01422 .02097	1,896 2,046	00100 00524	-6.6 -20.0	3
Volumetric Charge	169,905	-06282	10,673	169,905	.05258	8,934	01024	-16.3	` '\$
Total G-P28 - Std. Rate:	169,905	.14691	24,960	169,905	.12445	21,145	02246	-15.3	6
G-IND (2)(15)				Land Section	in the second	101 Y 1	ا الله الله الله الله الله الله الله ال		AND DESCRIPTION OF PROPERTY.
Customer Charge	698	734_87/HO	6.157	L98"	533.59/NO	4,47T.	-201.28/MO	-2724	7 4 4 4 6
Demand-Change T (3)	1,497,114	.04356	65,214	1,490,296		64,785	00009	2	gradient de la company de la c
Demand Change 2*(4)			and the second	140m - n 1 m 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1		•			•
Summer (5)	1,386,935	.00753	10,444	1,437,407		11,826	-00070		10
Volumetric Charge (70/13)	1,054,965	-01585 -06037	16,721	1,065,782	.01565 .05304	16,678	00020 00733	-1.3	11
Volumetric Charge (7)(13)	1,470,672	.00037	85,786	1,471,628	.03304	78,052	00755	-12.1	12
S-IND - Std. Rate	1,470,672 91,170	.12737	187,323 4,885	1,471,628	.11947	175,812 4,888	00790	-6.2	13 . 14
				- 410 500					
Total Industrial	1,561,842	12307	192,211	1,562,798	_11563	180,700	00745	-6.0	775
JTILITY ELECTRIC GENERATION		10 Te		1.	(, e ,	¢2,30 μt Carlos	137 9	xw5m	
Customer Charge	1	96,167/MQ	1,154	845 F	73,275/MO	879 -	275MS	-23.8	16.
Demand Charge (9)			104,974	Solver Comment	No. of	91,711	-13,263MS	-12:6	17
Volumetric Charge				· ·		/		20/0	18 - 5 - 20, 3040
Tier I (10) Tier II (11)	242,137 1,220,463	.06385 .02722	15,460 33,221	270,581 1,192,019	.05055 .02146	13,679 25,584	•.01329 •.00576 ⁵⁷⁶	-20.8 -21.2	19 20
1147 11 (11)	1,220,403	-02/22	35,221	1,,172,017	.02140		00575	-41,4 	~
Total G-UEG	1,462,600	.10585	154,809	1,462,600	.09015	131,853	01570	-14.8	¹ 21
r			4.5	p .				.	
GENERATION (15)		10440	43.764	fas AT	.09015	ET 000	-0 400		"
G-COG - Std. Rate Plus GC-2	588,931 65,690	. 10660 · .	62,781 3,622	588,931 65,690	-07015	53,092 3,622	-9,689	-15.4	- 22 , - 3 (1,1-1,1)
- 103 00-2 /	05,070		3,022	07,070					
Total Cogeneration	6\$4,621	-10144	66,403	654,621	.08664	56,714	-9,689	-14.6	24
UBTOTAL ""				, , , , , , , , , , , , , , , , , ,	2,5 4.	<u>.</u>	, W.	-1 -23	•
(Net of GC-2):	3,692,108	-11643	429,873	3,693,064		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
DLESALE (12)		.,	l		Land Company	3, 45		2 5.4 556	
Demand Charge (9)	•	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1	9,317	* 0 X 47 x - 2	gramma and the second	10,093	_ 1.676MS	18.0	27
Volumetric Charge	137,390	.01275	1,752	137,390	.01304	1,792	.00029	/- 2.5	28
Total Wholesale	137,390		11,069	137,390		12,785	.01249	15.5	20 3 " - p (1 2 2 2 2 2 2 2 2 2
TAL NONCOOK 47/A								,,,	19 0 0 (196
TAL 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_		449,452	3,987,314		403,197	01163	-10.3	31
· manage of the second									• •
-									

Jan. 1.

AVERAGE YEAR

TABLE 4

CAS DEMAND AND THROUGHPUT FORECASTS REFLECTING SETTLEMENT ADJUSTMENTS (MMDTH) (MMDTH)

		`.s -	/	•• /	
Line No.		Andrew Commence of the Commenc	GAS DEMAND	CURTAILMENTS,	<i>^</i> ~ \ <i>^</i> ~ \ .
1		, , , , ,, , = , = ,			<u> </u>
2		1 1 1 K	217.2	.0	
2		6.4	90.6		Strosm 7 90.6
,	Interdepartmental	,. 	.2	.0	15 - 15 mg
4	PG&E Start-up Fuel	ă.	1.4		یکی در به مواده در ایابی و ۱۹
į			•••••		4.4
5	. Total Core		309.5	.0	್ಲಿ
	Noncore Throughput			224 2500 75	
6	Teducaries (2002)			Constitution of the second of	ราวแล้ดนี้ 🦯 🤄
7	Industrial (P2B) **	, , ;;	17.5		- 17.5
/,	Industrial (P3-4) **		138.3		ggba138.3
8,	Industrial (GC-2)		9.1	(0.00) .74	
9	SCE Cool Water (G-IN	D)	23.9	gunta kina da da 🕺 🕹	640 202 9.19
10	Steam Heat (G-IND)	T P Company	1.1	(U, 1 · □) • ∑ • •	∰ ლოფ უ 323 . 9 ∯ .]
11	. Interdepartmental (C.	TNN	Ç.	Land Burgara	ស្រាស់ជាសាសាលាក្រី 1.1 ភ្នំភ្នំ ប
12	Cogeneration (G-COC)	- 400/		(337-3) 3-0	ე
13	Cogeneration (GC-2)		63.0	- ` - O	ეუს დღდ (63.0 %≨
14	EOR (GC-2)		6.6	.0	6.6
15		\$ 150 m	50.6	1.8	
4.7	Wholesale (C-WRT)	2.00	13.7	.0	13.7
7.0					
16	Subtotal		323.9	1.8	g 5 0 322.1
17	UEC-PC&E		164.4	18.2	
					146.3
18	Total Noncore		488.4	20.030	ស្រាស់ ខែ ស្មីស្មាស់ ដី - នេះ បែ
	7.5	Recognition (Co.	400,4	20.0	468.4
	Other				ra tordat 🗘
19	Gas Department Use		^ ^	200	hand end
20	Lost & Unacct For (LU	A 1754	8.2		ე გაი აგ.2 - 99 -
	TOSE & OWNERS FOR (TO	AL)	17.5	.0	17.5
21	Tanal Ask	,		******	
41	Total Other		25.7	.0	25.7
•		•	·		
22	Total On-System	N . 75	823_6	20.0	Light to the second of the sec
23	Interutility	and the second	50.0	40.0	803:46
	and the second s		20.0	.0	50.0
24	CRAND- TOTAL		072 (
		3 - 40 - 1	873.6	20.0	853.6
	p company of the section	phops products the seek off			

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

Andrew Contraction

COLD YEAR

TABLE 5

CAS DEMAND AND THROUGHPUT FORECASTS
REFLECTING SETTLEMENT ADJUSTMENTS
(MMDTH)

			\	••7
	e By Customer Class:		GAS DEMAND	
	Core Throughput			CURTAILMENTS THROUGHPUT
	l Residential		- •	
	2 Commercial	1.0	249.0	.Oj - m om maŭ 249.0
	3 Interdepartmental	CA1	99.5	1
	A DCCE Commencal	4.4	.2	0
•	4 PG&E Start-up Fuel		1.4	30.00 go • 0 .000 ba500
	<u> </u>		******	1.4
	5 Total Core	2	350.2	.0 350.2
	Noncore Throughput			ಕಟ್ಟು ಎಲ್ಲಾಗಳು ಅದ್ಯಾಥಕಾಗಿ
6	Industrial (pan)			และ วูร์กรรูว รูเมริสตรและครั้ง อั
-	THE CASE TAGE (FAD) WA	2.33	17.5	The second of th
,	Industrial (P3-4) **	·	138.3	(1.55) • Oszmanuba 17.5
9	Industrial (GC-2)	100	9.1	(ປູນວົວ) • 0×3 ແລະ ພາຍຫ າ 138.3 ໃ
9	SCE Cool Water (C. TM))) (6)	23.9	(a) (a) (a) (a) (b) (b) (b) (b) (b) (b) (b) (c) (c) (c) (c) (c) (c) (c) (c) (c) (c
10	C. Steam Heat (C-IND)			້ ກໍ່ຄູ່ກໍ່ສູງ • O ແລະ ເຄຍຄະ ປ23 . 9 ປີ ເ
11	Interdepartmental (C.	TATRI	1.2	Jan J. 1,25
12	Cogeneration (G-COG)	(ממז.	1	1
13			6 3.0	63.0
14		20 10	6.6	
		3 1 J	50.6	
15	Wholesale (G-WRT)		14.6	19. 13.5 Albano (ad 47.1 02)
			44.0	.0 14.6
16			204	
17	UEC-PC&E	, ,	324.9	3.5 Papa 0321.5 W
			164.4	33.5 130.9
18	Total Noncore			
	TACAT WOUGOLS	5 (75	489.4	
	0-1			~~~
	Other			ର ଜଣ୍ଡ ଜଣ ୍ଡ
19	Cas Department Use		8_8	and the property of white a figure
20	Lost & Unacct For (LUA	EV.		y kin Sign g . O 54,6\$1 ≥ ±548 .8 1 \$\$
	101 (20)	wy, s	17.5 ^{7%}	.0 17.5
21	Total Other	~ ~ 1		
	o chież		26.3	.0 26.3
22	Tabal As a			26.3 37.0 \\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\\
23	Total On-System	2.3	865.9	22 (23)
43	Interutility	1	50.0	37.0 v/1/1=1828;91 (3)
	A Section of the sect	Service Service	20.0	.0 50.0
24	GRAND TOTAL		****	
	and the second s	4 4 7 3	915.9	37.0 878.9
	and the state of t	-		

^{**} Reflects a 3.0 percent increase in PG&E's original forecast. Washington www

APPENDIX D Page :21 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.

Strace Ziona GRACE WONG