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Decision 98-06-073 June 18, 1998

ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for authority to adjust its gas rates and tariffs to be effective January 1, 1998, pursuant to Decision Nos. 89-01-040, 90-09-089, 91-05-029, 93-12-058, 94-07-024, and 95-12-053.	Application 97-03-002 (Filed March 3, 1997)

(See Appendix A for List of Appearances.)

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OPINION

1. Summary

This decision addresses Pacific Gas and Electric Company's (PG&E's) Biennial Cost Allocation Proceeding (BCAP) application. In this decision, we adopt an annual $97.7 million decrease compared to revenues from Gas Accord rates in effect on March 1, 1998, reflecting an annual decrease of $6.23 million in procurement revenues and an annual decrease of $91.43 million in transportation revenues. Appendix B attached to this decision shows the proposed revenue requirement, balancing account summary, and the rate impact of changes from this decision. All rate changes will be effective September 1, 1998.

This BCAP differs from those in years past, in that many parties were able to resolve many of the issues initially in contention. This is in contrast to previous PG&E BCAPs, which were hotly contested and often quite litigious. We consider the parties' agreements as joint testimony, rather than as a settlement, since the joining parties did not technically follow the Commission's settlement rules. (See the Commission's Rules of Practice and Procedure, Rule 51.1 *et seq.*) After separately analyzing each issue presented in this case, we adopt the two sets of joint testimony sponsored by many, but not all, of the parties, with minor modifications set forth herein. We also address the remaining few outstanding issues not covered by the two sets of joint testimony, which include Demand-side Management (DSM) cost allocation, and several policy issues dealing with the Market Center Account and Transwestern and Core Procurement Incentive Mechanism (CPIM), and Gas Supply Cost Forecast issues.

Since the underlying intent of the parties' joint testimony was to have the PG&E BCAP rates in effect for two years, this decision directs PG&E to file its next BCAP application no later than October 29, 1999, allowing the rates adopted in this decision to be in effect for two full years.

2. Procedural Background

PG&E filed its BCAP application on March 3, 1997. PG&E's initial application sought to establish gas rates for a two-year test period, from January 1, 1998, through December 31, 1999.

At the time PG&E filed its BCAP application, the Commission was conducting an experimental implementation of procedures that have become mandatory for our proceedings, effective January 1, 1998, pursuant to Senate Bill (SB) 960. (Ch.96-0856.)[1] After an April 17, 1997, prehearing conference at which both the Assigned Commissioner, President Bilas, and Assigned Administrative Law Judge (ALJ) Econome were present, President Bilas issued a ruling and interim scoping memo (April 17 ruling) identifying this application as a candidate proceeding to be processed under the experimental rules. The April 17 ruling also categorized this proceeding as "ratesetting" as defined in Experimental Rule 1.d. The ruling also granted the Office of Ratepayer Advocates' (ORA) motion to temporarily suspend the rate case plan procedural schedule pending the issuance of a Commission decision in the pending Gas Accord Application.[2] The parties unanimously supported this motion. Although all parties' rationale in support of the motion were not the same, a common underlying thread was that suspending the BCAP schedule would be the most efficient use of parties' and the Commission's resources, rather than litigating

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[1] The Experimental Rules and Procedures, adopted in Resolution ALJ-170, establish the rules and procedures for the experiment and the creation of the sample of proceedings to which the experimental rules will apply. All further reference to the "Experimental Rules" are to the experimental rules contained in Resolution ALJ-170.

[2] PG&E filed Application (A.) 96-08-043, together with a motion in many of its pending proceedings, which sought Commission approval of a broad settlement known as the Gas Accord. The assigned ALJ in A.96-08-043 issued a ruling consolidating the proceedings covered by the motion solely for purposes of considering the Gas Accord.

issues which might be resolved, or at least narrowed, by the Commission's Gas Accord decision.

On August 1, 1997, the Commission issued Decision (D.) 97-08-055 (the Gas Accord decision). On September 17, 1997, President Bilas and ALJ Econome held a second prehearing conference to set the schedule and to scope issues. Prior to the prehearing conference, ORA and The Utility Reform Network (TURN) filed a motion to strike PG&E's testimony proposing modifications to the adopted long-run marginal cost methodology. An October 6, 1997 ruling and scoping memo (scoping memo) granted the motion on the grounds that under the Gas Accord, the methodology for allocating distribution costs will not change for the term of the Gas Accord. The scoping memo also directed PG&E to serve amended testimony reflecting this ruling, and set forth a procedural schedule and issues to be addressed. The scoping memo also designated ALJ Econome as the principal hearing officer pursuant to the Commission's final rules implementing SB 960 after January 1, 1998,[3] and set forth a schedule under which the Commission would issue a decision in this matter no earlier than 30 days after the issuance of the proposed decision, assuming a submission date of March 13, 1998, and the issuance of the proposed decision by June 11, 1998. PG&E served its revised testimony according to the scoping memo's schedule, as did other interested parties.

At the next prehearing conference prior to the start of hearings, President Bilas and ALJ Econome delayed the start of hearings for several days based on

[3] The Commission's final rules implementing SB 960, as set forth in the Commission's Rules of Practice and Procedure (Rules) apply to this proceeding after January 1, 1998. (See Rule 4 (b) (1).) Rule 5 (k) provides in relevant part that, in ratesetting proceedings such as the instant case, the Assigned Commissioner should designate the principal hearing officer prior to the first hearing in the proceeding.

the parties' representations that they might reach a joint recommendation on many issues in the case. At the next prehearing conference held on February 2, 1998, many but not all, of the active parties stated that they were able to join in a stipulation and joint testimony, and had served this joint testimony prior to the prehearing conference. Most of the revised testimony and the joint testimony assumed a BCAP test-year period from September 1, 1998 through August 31, 2000. The parties also waived closing argument before President Bilas. Evidentiary hearings were held before ALJ Econome on February 3 and 4, 1998. No party requested final oral argument before the Commission within the time specified by the scoping memo, or at any other time. (See Rule 8(d).)

Altogether, the Commission held seven days of hearings in this case, and Commissioner Bilas was present for three of those days. The final decision is timely issued. It is issued prior to the date anticipated in the scoping memo, and well before the 18-month time period set forth in SB 960, Section 1 (uncodified portion).

The parties filed opening briefs on February 27, 1998 and reply briefs on March 13, 1998, after which the matter was submitted. In addition to PG&E, ORA, and TURN, the following parties sponsored testimony, participated in the hearings, or filed briefs: the California Industrial Group and California Manufacturers Association (CIG/CMA), Electricity Generation Coalition (EGC), City of Redding, James Weil, and Wild Goose Storage Inc. (Wild Goose).

3. Joint Testimony

This BCAP differs from those in years past, in that many parties were able to reach an agreed-upon result for many of the issues initially in contention. This is in contrast to previous PG&E BCAPs, which were hotly contested and often quite litigious. The parties set forth these agreed-upon resolutions in written and oral stipulations and testimony. The principal vehicles include Exhibit 7, a stipulation and joint supplemental testimony of ORA, TURN, and PG&E on a wide variety of issues including throughput estimates, treatment of various account balances and credits, commercial rate design, and other allocation issues such as distribution cost allocations to large distribution customers. (BCAP Joint Testimony.) Exhibit 8 consists of the stipulation and joint testimony of the EGC, City of Redding, and PG&E on electric generation gas ratemaking issues. (Electric Generator Joint Testimony). PG&E and TURN also presented a oral agreement to defer a 1999 Electric Utility Generation (UEG) meter issue to the next BCAP. Most parties either accept or do not dispute the outcome of the stipulations and joint testimony, but several issues remain contested by a few parties.

The parties sponsoring the stipulations and joint testimony urge us to view and adopt the agreements as a whole. PG&E states that the fact that various parties, with their different perspectives, were able to reach consensus among themselves on so many issues is a strong indication of the reasonableness of the stipulations. Mr. Weil, who did not join in the stipulations and joint testimony, urges that the Commission address the issues set forth in the stipulation and joint testimony individually. Mr. Weil states that the parties served Exhibits 7 and 8 only two days before the hearing began, and did not follow the Commission's settlement rules, which allow parties 30 days to comment on a stipulation or settlement. (See Rule 51.4.) By not complying with the settlement rules, Mr. Weil states that the parties took the risk that the Commission would not accept the stipulations and joint testimony as an indivisible stipulation and settlement.

In our review of the record, we take into consideration that the parties sponsoring the stipulations and joint testimony agree that these documents should be considered as a whole, because of the tradeoffs inherent in the entire agreement. However, we agree with the ALJ's ruling at evidentiary hearings that

Exhibits 7, 8, and the oral stipulation of PG&E and TURN should be treated as joint testimony, since the parties did not present their stipulation and joint testimony in compliance with the Commission's settlement rules. (See Rules 51.1 *et seq.*) Therefore, although we are not bound to adopt the joint testimony as an indivisible whole, we will nonetheless consider the intent of the parties sponsoring the joint testimony that the Commission treat the agreements as indivisible as we separately analyze each issue presented.

4. Throughput, Marginal Demand Measures (MDMs), Corrections, and Adjustments

In their initial testimony, PG&E and ORA used a similar approach to forecast gas throughput, and made similar, but not identical recommendations. With the exception of the forecast for the industrial class, both PG&E and ORA utilized standard log-linear econometric models. These models forecast gas demand as a function of average gas rates, weather, and economic conditions. With respect to the industrial class, PG&E forecasts gas demand as a function of the growth in industrial production. ORA did not take exception to this forecast. In contrast, TURN based its forecast upon the occurrence of warmer than average weather conditions in PG&E's service territory.

The BCAP Joint Testimony adopts TURN's proposed throughput forecast as shown on Table 2 of Mr. Marcus' opening testimony (Exhibit 16), with an adjustment that the 5,000 Mdth currently shown in the Industrial Transmission class will be moved to the Electric Generation class to reflect the resolution of certain issues in the Electric Generator Joint Testimony. Mr. Weil also supports the BCAP Joint Testimony on this issue, arguing that it is reasonable because TURN's position is reasonable, in that TURN demonstrated convincingly that there is a long-term trend of increasing winter temperatures in PG&E's service territory.

In its initial testimony, TURN explained that average temperatures in PG&E's service territory have been increasing over time. This warming trend, according to TURN, requires a downward adjustment to the number of Heating Degree Days (HDDs) assumed to represent an "average" temperature year for the purposes of forecasting throughput. TURN's proposal, adopted in the BCAP Joint Testimony, is reasonable for use in this proceeding and we adopt it. Moreover, we anticipate that adoption of this forecast should better reflect PG&E's actual throughput during the BCAP period. As ORA explains, over the last several years, PG&E's adopted gas throughput forecasts have not reflected the warmer than average temperature conditions actually experienced, which resulted in adopted gas sales which were higher than actual demand. This situation contributed to the existing overcollection in the Core Fixed Cost Account (CFCA). In contrast, we anticipate that TURN's demand forecast should better reflect PG&E's actual throughput during the BCAP period. We also adopt the correction associated with the Electric Generator Joint Testimony, since we adopt that Joint Testimony. (See Section 24 below.)

The BCAP Joint Testimony also proposes that TURN's proposed MDMs, as corrected by Mr. Aslin of PG&E and shown on Table 1A of Mr. Aslin's rebuttal testimony (Exhibit 3), should be used for this proceeding. However, the joining parties also agree that further study is needed to identify ways to develop a common methodology for the purpose of forecasting temperature conditions in future proceedings. To that end, PG&E will convene a workshop on forecasting temperature conditions open to all interested parties no later than six months prior to the date it files its next BCAP application. We find this proposal, to which no party objects, reasonable and adopt it, with the proviso that PG&E is to convene this workshop six months prior to its initiation of the BCAP or other type of proceeding which may serve similar functions in the future.

The BCAP Joint Testimony also makes two other minor corrections which we adopt. First, it corrects an error in data in a service level study to shift certain loads from the industrial class to the cogeneration class. Second, TURN has withdrawn its concern regarding loads associated with small commercial migration.

5. Core Fixed Cost Account (CFCA)

In its initial testimony, PG&E recommended amortizing the December 31, 1997, CFCA balance over a two-year period, whereas ORA recommended that the Commission amortize the April 30, 1998 CFCA balance, including forecasted interest, over a one-year period. The BCAP Joint Testimony provides that PG&E should amortize the revision date balance over a 12-month period with no forecasted interest. For purposes of the joint testimony, "revision date balance" is the forecasted balance for the month end immediately preceding the BCAP rate change, which in this case is the end of August, 1998.

The CFCA is a cyclical account and its balance can vary due to the amount of gas PG&E sells over the year, making the accuracy of adopted gas throughput forecasts extremely important. The parties are all in agreement that adoption of the joint testimony on this issue is expected to reduce the existing balance in the CFCA to a reasonable level. This being the case, we believe the joint testimony on this issue is reasonable and adopt it.

6. Storage Transition Cost Subaccount

PG&E forecasted a $18.2 million undercollection in the Storage Transition Cost Subaccount. PG&E states that this amount, updated to the actual balance, will be shared between core and noncore on an equal-cents-per-therm basis. In correspondence associated with PG&E's tariffs for the Gas Accord, PG&E agreed to absorb 100% of the core's share of the balance. In its initial testimony, ORA recommended that PG&E absorb 100% of the core's share of the storage transition cost subaccount balance as of March 31, 1998. TURN supported ORA's initial position.

The BCAP Joint Testimony adopts ORA's position on this issue as more fully set forth in Exhibit 12, pages 4-6 to 4-8. In addition, the joint testimony provides that ORA will audit the final balance in the storage transition cost subaccount at a future date to ensure proper accounting. No party objects to the joint testimony on this issue. This provision is reasonable, consistent with the Gas Accord, and we adopt it, with the modification that ORA complete this audit no later than 60 days prior to the date when PG&E files its next BCAP application, or by August 30, 1999.

7. Enhanced Oil Recovery (EOR) Balancing Account

PG&E initially recommended allocating both the undercollected balance in the EOR balancing account and the forecast period EOR revenue credit by an equal percentage of distribution cost. PG&E states it made this proposal because there is no longer an equal percentage of marginal cost (EPMC) allocator for all customer classes as a result of the implementation of the Gas Accord's embedded cost-based rates. Therefore, PG&E proposed a new allocation method. ORA did not object to PG&E's proposal. TURN, however, recommended that the existing undercollection in the EOR balancing account be allocated by EPMC, rather than by equal percentage of distribution cost. TURN reasoned that the existing balance resulted from past erroneous forecasts, so that the undercollection should be allocated in the same manner that the original credits were allocated.

The BCAP Joint Testimony adopts TURN's proposal to allocate the balance in the EOR Balance Account using the EPMC allocation adopted in PG&E's last BCAP, D.95-12-053, 63 CPUC2d 414. This proposal is reasonable and we adopt it, since this method ensures that the undercollection in this account is refunded in the same manner in which it was collected.

Although not addressed in the joint testimony, PG&E proposed to allocate the forecast period EOR revenue credit on a going-forward basis by an equal percentage of marginal distribution cost allocation. No party objects to this proposal. PG&E states this method would allow a change to the allocation method which recognizes the changes in marginal cost resulting from the Gas Accord's use of embedded cost for transmission and storage. Therefore, we also adopt PG&E's proposal to allocate the forecast period credit on a going-forward basis by an equal percentage of marginal distribution cost allocation.

8. Interstate Transition Cost Surcharge (ITCS) Account

The ITCS account is composed of costs associated with unutilized interstate pipeline capacity and capacity brokered at prices below the as-billed rate. In the Gas Accord, PG&E agreed to absorb 100% of the core portion of the ITCS charges from the inception of the ITCS account. For the noncore customers, PG&E agreed to absorb 50% of the noncore portion of the ITCS charges.

In its initial testimony, PG&E proposed to amortize the projected core ITCS overcollection over a 12-month period. ORA initially recommended that the ITCS balance be transferred to the CFCA. ORA reasons that (1) there is no need to extend the life of the ITCS account for another full year; and (2) transferring the core ITCS overcollection to the CFCA will help to reduce the undercollection in the CFCA. ORA also recommended that PG&E update the balances for both the core and noncore ITCS accounts through February 28, 1998, to reflect the Gas Accord's March 1, 1998, implementation date.

The BCAP Joint Testimony adopts ORA's proposal, to which no other party objects. This proposal is reasonable and we adopt it, since it is an administratively simple and equitable treatment for this account.

9. Transwestern Pipeline Demand Charge Credits

ORA initially proposed that PG&E be required to update the Transwestern Pipeline demand charge credits to reflect charges for the period subsequent to June 30, 1997, through the implementation of the Gas Accord. In its rebuttal testimony, PG&E notes that upon implementation of the Gas Accord, the net costs for Transwestern Pipeline capacity for the period prior to January 1, 1998, which were included in balancing accounts, will be removed from these accounts, and the costs of Transwestern Pipeline demand charges will fall upon PG&E shareholders for that period. For this reason, PG&E notes that no changes to the accounting for Transwestern capacity credits are necessary in this proceeding. ORA clarified that it did not intend that credits for brokering Transwestern capacity be awarded to ratepayers for the period during which PG&E shareholders are absorbing Transwestern capacity costs, and has withdrawn its initial recommendation.

The BCAP Joint Testimony adopts PG&E's proposal to make no change to the accounting for Transwestern capacity credits. No other party objects to this proposal, which is equitable, and we adopt it.

10. Customer Accounts Costs

In its initial testimony, TURN proposed two adjustments to customer account costs, primarily so that treatment of these costs would be consistent with PG&E's last BCAP decision, D.95-12-053. First, TURN proposed that $1,305,000 in customer accounting costs associated with Major Account Representatives be directly allocated to the large commercial, industrial, and cogeneration classes rather than be assigned the standard allocator. Second, returned check charges and charges for reconnection totaling $1,765,000 should be subtracted from marginal customer costs. TURN states that the returned check and disconnection and reconnection charges are charged to individual customers and are therefore not marginal costs. ORA initially did not take a position on this issue.

The BCAP Joint Testimony adopts TURN's position on these issues, and no party objects to this proposal. This proposal is reasonable and we adopt it, because TURN's proposal is consistent with our treatment of these identical issues in PG&E's last BCAP, D.95-12-053.

11. Noncore Eligibility

PG&E initially made a proposal which it stated would make it easier for most existing noncore customers to maintain noncore eligibility. PG&E explains that this change is necessary to reduce the problems that result under current requirements when PG&E is required to reclassify noncore customers back to core because of minor changes in production or temperature. The PG&E proposal deals with maintaining noncore eligibility, and is not a change to the current noncore definition to establish noncore eligibility adopted in D.95-12-053.

Under PG&E's proposal, a noncore customer could retain noncore status by using at least 20,800 therms in one month of the previous 12 months as of the effective date of this BCAP decision.[4] Customers who do not use this minimum in any of the previous 12 months would be reclassified as core customers. Under the existing standards for maintaining noncore status, a customer must either (1) use at least an average of 20,800 therms per month in a 12-month period, excluding those months where use was 200 therms or less, where the customer obtained its noncore status after January 1, 1996; and (2) customers who were

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[4] PG&E explains that noncore customers who were previously reclassified from Priority P-1 to Priority P-2B under the Agreement for Reclassification to Priority P-2B, as of September 30, 1993, will remain eligible for noncore status as long as they wish to take service as a noncore customer.

classified as noncore prior to January 1, 1996, would remain noncore, regardless of use, until the next BCAP cycle begins.

No party in this proceeding objected to the merits of PG&E's proposal. However, TURN proposed that PG&E send a notice to customers who would be reclassified as core customers under PG&E's proposed changes to inform them of the pending change in their status. ORA did not take a position on this issue.

As part of the BCAP Joint Testimony, PG&E agrees to provide written notice on a voluntary, nonprecedential basis to noncore customers who would be reclassified to core under PG&E's proposed change to the standards. In its opening brief, PG&E states it will provide such notice upon issuance of the ALJ's proposed decision. An ALJ ruling issued contemporaneously with the issuance of the proposed decision directed PG&E to mail written notice to persons who could be affected by PG&E's proposal that the proposed decision recommended adopting. The ALJ ruling directed PG&E to mail such written notice to affected parties no later than seven days after the mailing of the ALJ's proposed decision. This notice should be made in sufficient time for affected parties to examine their usage in light of the new rules. No party objects to the joint testimony on this issue and we adopt it.

12. California Alternate Rates for Energy (CARE) Administrative and General (A&G) Credits

PG&E initially proposed changing the current allocation of CARE A&G credits from EPMC to an allocation based upon the same method as the CARE subsidy, CARE A&G, and CARE balancing account costs are allocated. ORA recommended that CARE A&G credits be allocated on the basis of equal percent of marginal distribution cost. Under the ORA proposal, the core would receive 94% of the credit, which ORA states is similar to what the core class would have been allocated under an EPMC allocation. ORA states that PG&E's proposed change results in the core class obtaining 58% of the credit.

In its initial testimony, TURN disagreed with both PG&E and ORA. TURN stated that in the last PG&E BCAP, D.95-12-055, 63 CPUC2d at pp. 437-438, the Commission found that the costs of administering the CARE program should be recovered in the same manner as other CARE costs, and not as customer accounts-related marginal costs. In the last BCAP, TURN proposed to reduce the variable customer-related marginal costs for customer accounts by the amount of CARE administrative costs. All classes' customer accounts were reduced on an equal percentage basis, resulting in the residential and small commercial classes receiving 98% of the credit. The rationale underlying TURN's proposal is that these administrative costs were originally included in residential and small commercial customer accounting costs, and therefore these customers should be allocated the credit.

In this proceeding, TURN proposes to allocate the A&G credit in a manner closely approximating the way costs would otherwise show up in customer accounts expense. To achieve this, CARE A&G credits would be allocated to customer classes based on customer-related marginal cost revenue, as more specifically set out in TURN's testimony at Exhibit 17, page 11. This approach allocates the vast majority of the credit to residential and small commercial customers, which is consistent with TURN's proposal in the last BCAP.

The BCAP Joint Testimony adopts TURN's position on this issue, to which no party objects. We adopt this proposal because it is equitable and consistent with the last BCAP decision.

13. Rate Design

This case presents three rate design issues: (1) commercial rate design; (2) core deaveraging; and (3) commercial customer class charge. PG&E stresses that although these issues are conceptually different and separable, the commercial rate design which emerges from this proceeding will result from the combined impact of all three issues and resolutions. Therefore, in reaching their recommendations in the BCAP Joint Testimony in the area of rate design, the joining parties made trade-offs and weighed the overall impact of all three issues. PG&E requests the Commission take into consideration that the rate design proposals represent a single, unified outcome for these three issues. As stated in Section 3 above, we take this fact into consideration, but are not bound to consider the agreement as a package since it is not a settlement subject to Rule 51.1 *et seq.*

13.1. Commercial Rate Design

PG&E initially proposed a two-tiered declining block rate structure for both small and large commercial customers in order to solve the "rate cliff" problem that it states exists among commercial customers. "Rate cliff" refers to the existing situation where certain commercial customers have the incentive to burn more gas than they would otherwise use in order to qualify for a lower rate. PG&E initially proposed to end the first tier at 2000 therms per month, but in its rebuttal testimony provided examples of two-tiered blocks with different volumes in the first block. Along with the different initial blocks, PG&E also provided estimated maximum bill increases as the size of the first tier varied. At 2000, 3000, and 4000, therms the bill impacts are 7.2%, 4.2%, and 2.7%, respectively.

While sympathetic to PG&E's concerns over the rate cliff, ORA initially opposed PG&E's proposal because it would produce adverse bill impacts for some lower volume customers. In particular, ORA noted that some small commercial customers' bills could increase by as much as 9.4%. TURN also agreed that the "rate cliff" which PG&E identified deserves attention, but shared

ORA's concern regarding a possible adverse impact for some lower volume customers.

After reviewing PG&E's rebuttal testimony, the joining parties recommend in the BCAP Joint Testimony that the Commission adopt a two-tiered block rate design during the first year of the BCAP. This proposal differs from PG&E's initial proposal in that the first block would end at 4000 therms instead of 2000 therms. The parties explain that this type of two-tiered declining block rate structure minimizes the bill impacts for small commercial customers. TURN also stresses that it believes that this proposal is reasonable especially in light of PG&E's concession on the other rate design issues discussed below. No other party objects to this proposal.

Because the two-tiered rate structure set forth in the BCAP Joint Testimony addresses the "rate cliff" problem identified by PG&E without adversely impacting lower volume customers, it is reasonable and we adopt it.

13.2. Core Deaveraging

PG&E initially proposed to deaverage residential and small commercial rates by 50% during the second year of the BCAP. ORA, TURN, and Mr. Weil initially opposed PG&E's core deaveraging proposal. ORA and Mr. Weil argue that in the event the Commission adopts PG&E's pending general rate case proposal for a 28.1% increase in residential gas rates, then 50% core deaveraging could result in what they describe as "rate shock," since residential rates could increase as much as 29.8%. ORA also pointed out that PG&E did not perform a complete core deaveraging analysis of all classes or sub-classes, and therefore recommended that the issue of residential rate flexibility and choice be examined in PG&E's next BCAP. Mr. Weil contended that any rate increase exceeding 15% will cause rate shock. In its rebuttal testimony, PG&E stated that it was open to a flexible implementation plan of rate deaveraging.

The BCAP Joint Testimony recommends 10% core deaveraging in the second BCAP year. ORA explains that deaveraging rates by 10% would increase residential rates by about 0.7%, while PG&E's initial 50% deaveraging proposal would increase rates by about 5.3%.[5] TURN believes that this modest deaveraging is reasonable, especially given PG&E's other concessions, particularly in the rate design area. Mr. Weil also supports the joint testimony on this issue, and no other party opposes it. Because the compromise presented in the BCAP Joint Testimony will result in a more orderly transition toward deaveraged rates, it is reasonable and we adopt it.

13.3. Commercial Customer Class Charge

TURN initially submitted a proposal for a core commercial customer charge in the event the Commission were to deaverage core commercial rates. TURN pointed out that an inequity exists for small commercial customers, namely, that small commercial customers have been cross-subsidizing large commercial customers with respect to customer costs. In order to address this problem, TURN proposed that the Commission adopt a customer charge of $9.50 per month, as opposed to the current level of $13.42 per month, for customers using under 1,000 therms per year on the basis of EPMC. In its rebuttal testimony, PG&E stated it did not oppose TURN's proposal, but instead preferred a multi-tiered customer charge. ORA did not take a position on this issue. PG&E also noted that it had not yet fully investigated the billing

[5] The ALJ requested that PG&E, ORA, and TURN provide a joint late-filed exhibit (Exhibit 23) showing the rate impacts of the BCAP Joint Testimony assuming that the Commission grants PG&E's test year 1999 general rate case application request in its entirety. Revised Exhibit 23 shows that 10% core deaveraging would result in a 0.9% rate increase for residential customers and a 2.9% rate decrease for small commercial customers, with an average core increase of 0.4%.

implications of the proposed change and that it would need some flexibility in developing implementation details.

The BCAP Joint Testimony proposes that small customers who use less than 1,000 therms annually will receive a reduction in the monthly customer access charge to $10.50 from $13.42. This change will occur in the second BCAP year and will commence in conjunction with the 10% core deaveraging discussed in Section 13.2. The BCAP Joint Testimony also sets forth several different detailed options for implementation, including two-tiered and multi-tiered alternatives. If PG&E chooses to implement a multi-tiered customer access charge, it may do so as long as the monthly charge for the smallest commercial customer remains $10.50 per month, and the monthly charge for the next usage tier is no higher than $13.50 per month. In order to better inform others about the implementation options PG&E ultimately selects, PG&E is to file an advice letter with workpapers prior to the second year of the BCAP to implement this change. No party objects to this proposal.

We agree with TURN that this proposal is reasonable because it better reflects the costs of serving small commercial customers, and ensures that these customers receive benefits from the core deaveraging proposal, and therefore we adopt it. PG&E is directed to file an advice letter with workpapers, served on all parties to this proceeding, no later than 60 days prior to the beginning of the second year of the BCAP, or July 2, 1999, to implement the change in commercial customer class charge adopted in this proceeding.

14. Distribution Costs Allocable to Large Distribution Customers

In its initial testimony, TURN noted that approximately 13% of PG&E's annual throughput on the "transmission-level" rate established by the Gas Accord was composed of customers who actually received their service at the distribution level. TURN points out that Schedule G-NT customers, who are eligible for transmission-level service but actually receive service at the distribution level, are responsible for 3.1% to 3.3% of the demand that drives marginal distribution costs, yet PG&E would not allocate any distribution costs to industrial transmission customers. TURN estimates that these customers are responsible for $12.4 million to $12.8 million of system costs that end up being paid by other distribution-level customers. Recognizing that the Gas Accord sets the rates for these customers through the term of the Accord, TURN recommends imputing the appropriate amount of revenue from these customers in setting other distribution customers' rates. The effect of this proposal is that shareholders would be responsible for these costs in the same way they are responsible, under the Gas Accord, for any revenue shortfalls attributable to discounts. In its rebuttal, PG&E stated that TURN had incorrectly calculated the impact of this issue by approximately $4 million. PG&E also stated that the adjustment proposed by TURN is precluded by the terms of the Gas Accord. PG&E primarily argues that the Gas Accord workpapers set forth the mechanics and process used to set distribution rates, and that because these workpapers were filed with the Gas Accord, they were part of the record on which the Commission based its decision.

The BCAP Joint Testimony reaches a compromise. As stated above, PG&E believes that the dollar impact of TURN's proposal is about $4 million less than the $12.4 million to $12.8 million TURN originally estimated. TURN accepts PG&E's correction. The joint testimony reduces PG&E's annual distribution revenue requirement by approximately $4.178 million annually for the two-year BCAP period. For the period from the end of the BCAP to the end of the Gas Accord, the joint testimony reduces PG&E's distribution revenue requirement by 50% of the distribution revenue requirement allocable to large distribution customers with loads in excess of 3 million therms per year. The Gas Accord period ends December 31, 2002, except that the period for gas storage services ends March 31, 2003. Mr. Weil agrees with the joining parties that this outcome is a reasonable resolution of the dispute. No party opposes this proposal.

The compromise set forth in the joint testimony on this issue is reasonable, and we adopt it. There are conflicting opinions about whether the Gas Accord was specific about distribution costs allocable to large customers and about the intent of the Gas Accord. Given these legitimate differences of opinion, and the fact that one side or the other might have had to bear 100% of these costs throughout the Gas Accord period, the compromise adopted by the joint testimony is a reasonable resolution of this issue.

15. Pipeline Demand Charge Allocation

PG&E initially proposed to allocate Pacific Gas Transmission demand charges, intrastate backbone charges, and Canadian demand charges to both core procurement and core transport customers on a consistent basis using average-year-peak-month (January) throughput. PG&E determined that its proposal would produce relatively minor adjustments to affected rates. PG&E argues that the minor impact from the change and the resulting ability to use a consistent allocation method support its proposal. ORA initially stated that it was in agreement with PG&E, and TURN did not take a position on this issue. The BCAP Joint Testimony adopts PG&E's position on this issue to which no other party objects. We adopt this proposal as reasonable.

16. Market Center Account

PG&E explained that since mid-1996, it has been offering interruptible parking and lending gas services through the Golden Gate Market Center (market center). PG&E committed to track revenues and incremental costs associated with the market center services in a Market Center Account. The Commission would determine the allocation of net revenues in this BCAP.

In its initial testimony, PG&E proposed that the net revenue accrued prior to the Gas Accord implementation be allocated equally between ratepayers and shareholders in order to share the benefits of market center services with all users of the system, and to compensate PG&E as an incentive for risk assumed in providing the services. PG&E also recommends that ratepayers' share of the account be allocated to different customer classes on the basis of equal cents per therm. For the period after the Gas Accord implementation, PG&E proposes that all revenues and costs should accrue to shareholders with no balancing account protection, since shareholders have all the risk associated with transmission and storage assets.

ORA disagreed with PG&E's proposal and instead recommended that PG&E allocate the entire Market Center Account revenue to PG&E's core customers. ORA reasons that PG&E shareholders assume no risk in providing market center services, and accordingly are not entitled to receive any revenue generated by the market center. In addition, ORA assumes that PG&E's operation of its market center services is similar to the manner in which Southern California Gas (SoCalGas) operates its Hub Services, namely, that core flowing supplies and core dedicated facilities are utilized to provide market center services. Finally, ORA relies on the Commission's decision in SoCalGas' last BCAP, D.97-04-082, as precedent for its recommendations here.

In its rebuttal, PG&E objected to ORA's proposal and provided additional information regarding how it provides market center services. First, PG&E objects to ORA's exclusion of noncore customers from sharing the Market Center Account balance. PG&E stated that the pipeline assets (transmission and storage) used to provide market center and balancing services are included in rates for all customer classes and are paid for by all ratepayers, including core and noncore. PG&E also asserts that core flowing supplies are not involved with providing market center services. PG&E's rebuttal also asserts that the operating policies governing PG&E's market center differ from those of SoCalGas'.

The BCAP Joint Testimony resolves this issue by allocating the balance in the Market Center Account accrued at the end of February, 1998, prior to the implementation of the Gas Accord, 75% to ratepayers and 25% to shareholders. The allocation between core and noncore would be based on a cold-year winter season rather than equal cents per therm. The joint testimony addresses the period prior to the implementation of the Gas Accord because, under the Gas Accord, PG&E shareholders are responsible for all the costs and receive all the revenues from market center services during the Gas Accord period, which began March 1, 1998. Although Wild Goose raised an additional policy issue discussed below, no party objects to this portion of the joint testimony.

We find the joint testimony reasonable on this issue and adopt it. The outcome proposed by the joining parties is reasonable in light of both the information PG&E provided in rebuttal regarding the operation of PG&E's market center and the litigation risks associated with the various proposals. Also, we recognize that the issue of allocating the Market Center Account is a one-time issue specific to this BCAP, since once the Gas Accord is implemented, PG&E will be at risk for the service. The portion of the joint testimony allocating the Market Center Account revenue to core and noncore classes based upon cold-year winter season is based upon the rationale that the revenues associated with the market center facilities would be allocated to the customer classes in the same fashion as the costs for those facilities were allocated. This methodology results in 54% of the revenue being allocated to the core and 46% to the noncore. Allocating revenues in the same fashion as costs is equitable to both the core and noncore classes.

Although not opposing the result of the joint testimony on this issue, Wild Goose states an additional concern. Wild Goose is an independent gas storage provider that will offer firm and interruptible gas storage service at market-based rates. Wild Goose's comments focus on PG&E's operations of the market center during the Gas Accord period from March 1, 1998 through December 31, 2002. Wild Goose is concerned about what it describes as the inherent conflict of interest PG&E faces when it chooses between offering market center services, thereby maximizing revenues for shareholders, and brokering excess core capacity through the core procurement department, thereby reducing core gas costs. In its opening brief, Wild Goose requests that the Commission direct PG&E to exercise all due diligence in marketing excess core pipeline transmission capacity and storage capacity on the core's behalf, prior to marketing any of this excess capacity to generate revenues that accrue only to the shareholders. Wild Goose states that its conflict of interest concerns are magnified by the fact that there appear to be no consequences or penalties for a violation of PG&E's internal policy against altering the core's purchases or injection rates to facilitate market center services.

PG&E disagrees with Wild Goose's arguments, and states that there are a number of factors in place to insure independent decision-making on behalf of the core. Besides the fact that these functions are performed by separate departments under separate officers, PG&E states that the core will communicate its needs using the same vehicles as other customers upon implementation of the Gas Accord. PG&E explains that the core procurement department has an objective of lowering the cost of gas to the core, and meeting or beating the benchmark under the CPIM, and that regulatory review of core procurement decisions and actions will continue into the foreseeable future, even under the Gas Accord. PG&E also explains that its core procurement department knows that it will be required to file reports on its activities. In its opening brief, PG&E recognizes that Wild Goose "seeks that the Commission direct PG&E's core procurement department to exercises all due diligence as a storage customer to maximize the value of its storage capacity on behalf of ratepayers, just as they should their intrastate and interstate transmission capacity, even to the extent of brokering excess storage capacity or offering market-center-type services." (PG&E Opening Brief at p. 28.) PG&E then states that Wild Goose's statement of position is consistent with PG&E's core procurement department's position on minimizing overall gas costs.

We are pleased here by PG&E's assurances, and wish PG&E to abide by them. Therefore, we direct that PG&E shall exercise due diligence in brokering excess core capacity on the core's behalf and shall use only any remaining capacity in offering market center services.

Wild Goose requests additional relief in its reply brief for the first time.[8] Apparently, Wild Goose now believes that even the relief Wild Goose requested in its testimony and opening brief will not ensure compliance because of what it terms the inherent conflict. Therefore, Wild Goose also recommends that the Commission consider the development of a long-term solution for addressing this issue in the Natural Gas Strategy Rulemaking, Rulemaking (R.) 98-01-011. The Commission and parties are scoping issues in our Natural Gas Strategy Rulemaking. We will not decide here the appropriate scope and timing of those issues, but rather direct all interested parties to participate in the Rulemaking.

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[8] It is procedurally incorrect for Wild Goose to raise this argument for the first time in its reply brief, when no party has the opportunity to respond thereto. However, since we do not adopt this argument here, no party has been harmed by Wild Goose's raising this issue in an untimely fashion.

17. Marginal Capacity and Customer Access Costs

As a result of agreements reached in the Gas Accord, the parties in this BCAP are following the marginal cost methods adopted in D.95-12-053, and are not litigating changes to marginal cost methodology. However, in this BCAP, the Commission needs to decide what the updated marginal costs should be. In the area of marginal costs, ORA and PG&E differed on only two issues: (1) the A&G loader; and (2) the replacement frequency for determining the replacement costs for services, regulators, and meters.

PG&E initially proposed an A&G loader of 32%. This factor is based upon a review of recorded 1995 A&G costs that were classified as either marginal or fixed. ORA recommended an A&G loader of 29%. ORA bases its recommendation on a review of PG&E's A&G programs, which indicated that PG&E had reclassified some of the program expenses from marginal to nonmarginal without providing supporting rationale for this reclassification. ORA recommends that PG&E be directed to remove these particular costs from its marginal A&G estimates. ORA's adjustment reduced PG&E's proposed A&G loader to 29%.

The BCAP Joint Testimony recommends the A&G loader be set at 29%. Given ORA's initial testimony, this figure is reasonable and we adopt it.

PG&E also initially proposed replacement rates of 1.56%, 3.29%, and 2.56%, respectively, for services, meters, and regulators. PG&E bases these percentages upon (1) the reciprocal of the service life, or one over the service life; and (2) the recorded historical annual data PG&E has for three different types of equipment. PG&E explains that the use of the reciprocal of the service life provides a data input which reflects a long-term estimate of replacement rates. By using the recorded historical information, PG&E also includes actual data on replacement rates, which data incorporates shorter term information. PG&E states that it had data ranging from two years for regulators to 12 years for meters, and used all the years for which data were available to develop the replacement frequency. PG&E then calculated the replacement frequency for each of the three types of equipment by averaging the service life estimates and the available recorded annual data.

ORA opposed PG&E's "averaging" approach for three reasons: (1) PG&E conceded that the long-run replacement frequency tends to overstate actual replacement; (2) PGE retained only two years of historical data for regulators, but retained 12 years of replacement data for meters; and (3) the historical approach did not capture the probability of replacement in the near-term BCAP period. In ORA's view, using the most recent five years of actual replacement rates to determine the replacement rates for service, meters, and regulators was more appropriate for this BCAP period. Based upon this methodology, ORA recommended replacement rates of 0.56%, 1.78% and 1.80%.

In rebuttal, PG&E stated that ORA's data set for replacement frequencies is too limited. PG&E points out that replacement rates fluctuate from year to year for a variety of reasons. For instance, PG&E maintains that as the population of equipment gets older, the failure rate increases. A large portion of PG&E's population of meters is about 6 to 10 years old. PG&E states that this equipment has been experiencing low failure rates in recent years, but believes that it will fail at higher rates as it gets older. Therefore, PG&E believes that historical data from a small time span, as ORA proposes, is unlikely to accurately capture the replacement rate.

The BCAP Joint Testimony proposes the Commission adopt replacement frequencies of 1.06%, 3.29%, and 2.56%, respectively, for services, regulators, and meters. The joint testimony resolves the differences between ORA and PG&E by adopting PG&E's replacement frequencies for meters and regulators, while developing a replacement frequency for services midway between the PG&E and ORA rates. PG&E believes that for purposes of this case, this result adequately incorporates the longer term data on service life and replacement rates. ORA believes that because the dollar impact of the figures adopted for replacement frequencies for meters and regulators is minor in comparison to the service line issue, the net effect of the joint testimony is to split the difference between the PG&E and ORA positions. ORA believes this is a reasonable result in light of the litigation risk associated with the different positions, the fact that the dollars at issue are relatively minor, and the compromises and trade-offs involving this and other issues to the joint testimony. No party opposes the joint testimony's proposal on this issue. For the reasons set forth by PG&E and ORA, the joint testimony on this issue is reasonable and we adopt it.

The BCAP Joint Testimony also incorporates the set of corrections proposed by TURN witness Marcus which are discussed in more detail in Section 10 above.

18. Franchise Fees and Uncollectibles

Mr. Weil's testimony identified a minor computational error in the calculation of franchise fees and uncollectibles within the BCAP revenue requirement. No party opposes this correction, which is adopted by the BCAP Joint Testimony. Because appropriate corrections should be included in this decision, this proposal in the joint testimony is reasonable and we adopt it.

19. Balancing Charge Account

A Balancing Charge Account (BCA) has been created with the implementation of the Gas Accord. The BCA will accumulate costs associated with balancing the system and revenues from the imposition of imbalance penalties. The net balance will be allocated to ratepayers on a basis which the Commission has yet to establish. Although there is nothing in the account yet, PG&E initially proposed to allocate the balance to all ratepayers on an equal-cents-per-therm-basis. PG&E's reasons that all customers benefit from PG&E's daily balancing of its gas system, so all customers should share the responsibility of associated balancing costs.

ORA disagreed with PG&E's proposal. In ORA's view, the costs incurred as a result of PG&E providing the imbalance service should be allocated to those customer classes who are responsible for incurring such costs or revenues. In order to prevent cross-subsidization of imbalancing costs and ensure that costs are properly allocated, ORA recommended that the Commission direct PG&E to accurately record and track the customer imbalance costs and revenues incurred for each class by rate schedule. The Commission could address the issue of the appropriate allocation of the BCA in PG&E's next BCAP, when information will be available regarding which customers are directly responsible for incurring system load balancing costs. TURN supported ORA's initial recommendation.

PG&E's rebuttal testimony did not oppose ORA's proposal to defer the establishment of the BCA's cost allocation methodology to the next cost allocation proceeding. PG&E also agreed to track gas imbalances to develop data for allocating the BCA balance. However, PG&E pointed out that it could not track imbalances as ORA suggested, but could only track imbalances by core and noncore classes, because of the information provided by the current nomination and balancing protocols.

The BCAP Joint Testimony provides that PG&E will track gas imbalance cash transactions by core and noncore classes, and not by end-use customer rate schedule. The joining parties also agree that the allocation of the BCA should be deferred until the next cost allocation proceeding.

Mr. Weil is the only party to oppose the joint testimony on this issue. Mr. Weil believes that the joint testimony is contrary to the Commission's intention stated in Resolution G-3288, and will produce skewed measurements of customer behavior. Mr. Weil believes that the record is sufficient to resolve the issue as it affects the core, and recommends that the Commission allocate all the BCA balances to noncore customers and core transporters, and not allocate any portion of BCA balances to core procurement customers whose balancing activities are managed by PG&E. Mr. Weil does not object to the joint testimony provision that PG&E will track imbalance data until the next BCAP, and for the Commission to consider cost allocation for other customer classes in the next BCAP.

Mr. Weil argues that because PG&E can directly control core procurement balancing activities, any tracking of future balancing data will produce a biased record of customer behavior. Mr. Weil contends that data tracking will not record independent measurements of core procurement balancing needs, but will reflect PG&E management incentives and conflicts of interest. This is because PG&E will manage gas balancing resources on behalf of its core procurement customers and its Electric Department, which will operate in a competitive regulatory environment and will be at risk for sales and cost variations. Although PG&E states that its core procurement managers and the Electric Department act independently, Mr. Weil states there is a reasonable possibility that corporate managers will act in ways that favor the Electric Department. Biased management of balancing activities is one possibility. For instance, Mr. Weil states that the Gas Accord requires that all customers must exercise their best efforts to have daily gas receipts match daily gas usage, yet PG&E has established a set of internal guidelines that allow noncore customers not to match gas balances, within certain tolerances. Mr. Weil believes that these standards are far less rigorous than the best efforts rule in the Gas Accord.

PG&E disputes Mr. Weil's arguments. PG&E states that its core procurement function is being run on a separate, stand-alone basis under the Gas Accord, like any other customer. PG&E states that core procurement is subject to the CPIM, which provides both rewards and penalties for core procurement performance. Finally, PG&E argues that PG&E's core procurement activity is still subject to the Commission's oversight and review.

We do not believe that the joining parties' proposal to defer this issue to the next cost allocation proceeding is contrary to Resolution G-3288, which addressed PG&E's Gas Accord tariffs. Resolution G-3288, slip op. at p. 16, states, in relevant part, that "ORA should address the issue of allocation of the balancing account in PG&E's BCAP proceeding." The issue Resolution G-3288 refers to can fairly encompass not only how, but whether to allocate the balancing account in this proceeding or at a future date.

The BCAP Joint Testimony is reasonable on this issue, and we adopt it, with the following clarifications. It is reasonable to defer this issue until we have data to determine the best allocation method. This data began to become available only after the Gas Accord was implemented on March 1, 1998. It makes sense to decide the cost allocation issue after, and not before, information on cost allocation is obtained.

However, our adoption of the BCAP Joint Testimony on this issue does not preclude parties in the next cost allocation or other appropriate proceeding from making arguments that the data should be discounted or that it is not helpful because PG&E has not exercised its management discretion fairly. The Commission will be in a better position to evaluate the types of arguments advanced by Mr. Weil after information on cost allocation and PG&E's management's behavior is obtained. Therefore, although we do not adopt Mr. Weil's position here, we do so without prejudice to him or any other party to raise the same or similar argument in the next BCAP or other type of proceeding which may have a similar function in the future.

20. UEG 1999 Metering Costs

In its opening testimony, TURN pointed out the PG&E's general rate case application includes a request for $14.5 million to improve UEG metering systems. TURN states that because customer access charges for noncore customers are fixed under the Gas Accord, noncore customers will be absolved of responsibility for those costs unless the Commission recognizes those costs as marginal costs for ratemaking purposes. TURN proposed that the Commission should require UEG metering costs recovery from the appropriate customer class after the expiration of the rate freeze occasioned by the Gas Accord. PG&E believed that this issue was beyond the scope of this BCAP. No other party addressed this issue, with the clarification that it be deferred to the first BCAP after the expiration of the Gas Accord, or other type of proceeding which may serve a similar function in the future.

PG&E and TURN have entered into an oral stipulation that the issue of the allocation of UEG metering costs should be deferred to the first BCAP after the expiration of the Gas Accord. In that future proceeding, each party would be free to take any position and to make any appropriate arguments without limitation, and that nothing in this oral stipulation may be used as precedent or an admission in any other proceeding. No other party opposes this agreement which is reasonable and we adopt it.

21. Transwestern and CPIM, and Gas Supply Cost Forecast

PG&E's initial testimony presented a gas supply cost forecast based on estimates of Canadian and Southwest gas supplies, gas prices, pipeline demand charges, and core transport customer loads. This part of PG&E's showing was largely uncontested, although there are two outstanding issues raised by TURN.

The first issue involves PG&E's estimate of gas supplies purchased for delivery over the Transwestern system. TURN notes that PG&E's forecast of prices for purchases of gas from the Southwest shows that the cost of gas purchased for delivery over the Transwestern system exceeds the cost of firm purchases at the California border by over 30 cents per decatherm on average. TURN states that, nonetheless, PG&E apparently intends to purchase Transwestern supplies ahead of other available Southwest supply options. Under the adopted CPIM, core ratepayers will bear from 50% to 100% of these excess costs, regardless of the fact that cheaper gas is expected to be available for purchase at the border. TURN argues that the Commission should at least consider whether this is the type of activity that an approved incentive mechanism should be structured to reward.

TURN argues when the Commission approved the CPIM in the Gas Accord decision, it also stated that the CPIM will not be the sole device by which the Commission will protect PG&E's ratepayers to the extent PG&E puts shareholder interests ahead of ratepayer interests and unreasonably purchases gas at prices higher than available alternatives. TURN states that since PG&E's shareholders are at risk for the costs of Transwestern capacity that remains unused, PG&E has a strong incentive to use that capacity and collect the demand charges from ratepayers. TURN argues that for PG&E to use more expensive shareholder capacity when cheaper capacity is available elsewhere is precisely the circumstance the Commission described in the Gas Accord decision. TURN argues that the Commission should reiterate to PG&E that the CPIM is intended "to minimize its procurement costs for core customers" [D.97-08-055, slip op. at p. 42], not to provide a means of utilizing otherwise idle shareholder assets.

PG&E states that TURN's testimony simply points out what happens under the operation of the CPIM. However, PG&E argues that the Commission approved the CPIM in D.97-08-055, and that this proceeding is not the proper forum to change or relitigate the CPIM.

TURN is asking us to revisit what we have stated in the Gas Accord decision, D.97-08-055, and we decline this invitation to do so in this proceeding.

The second issue raised by TURN concerns PG&E's failure to forecast any revenue from brokering excess core intrastate transmission capacity, even though that capacity is expected to lay idle for significant periods of time. TURN requests that the Commission make clear to PG&E that it is expected to exercise all due diligence in attempting to market unused core capacity, at discounted prices if necessary, in order to mitigate the cost of excess capacity for the core. TURN states that this is the "conflicts of issue" question which the Gas Accord did not remedy. TURN requests that the Commission here reiterate that PG&E is expected to act in the best interests of its ratepayers, regardless of the fact that it may achieve higher profit levels by pursing a different strategy.

PG&E explains that before implementation of the Gas Accord, intrastate transmission capacity has not been available for brokering. Therefore, at present, it is difficult to determine the credits that could be expected from brokering its capacity. PG&E states that the absence of an estimate for brokering revenues does not mean brokering will not occur. PG&E's witness How stated that PG&E core procurement will attempt to broker excess intrastate core capacity, if that results in a lower overall cost of gas to the core. PG&E argues that this articulation is consistent with TURN's position that PG&E should exercise all due diligence in attempting to market unused core intrastate capacity in order to mitigate the cost of excess capacity for the core, and that therefore no controversy exists over this issue. TURN does not agree, and calls for a Commission statement on this issue rather than just PG&E's assurances.

We agree with TURN that PG&E's assurances would have been more meaningful here if PG&E had forecasted revenues from brokering excess core intrastate transmission capacity, but it did not do so. Nevertheless, we are pleased with Mr. How's assurances that PG&E core procurement will attempt to broker excess intrastate core capacity, if that results in a lower overall cost of gas to the core. We wish PG&E to abide by these assurances, and therefore direct PG&E to use its best efforts in attempting to market unused core intrastate capacity in order to mitigate the cost of excess capacity for the core.

22. Procurement Revenue Requirement

PG&E used the gas supply cost forecast to develop a procurement revenue requirement. However, with the implementation of Core Monthly Pricing, PG&E states that the procurement revenue requirement's role in this BCAP is greatly reduced, and is only needed for two reasons: (1) to show the change from present rates resulting from PG&E's proposal and (2) to develop carrying costs of gas storage. No party presented testimony contesting PG&E's procurement revenue requirement. We adopt PG&E's showing on this issue for the limited purposes that a procurement revenue requirement is needed in this case.

23. DSM Cost Allocation

PG&E recommends that common costs allocated to DSM programs be directly allocated to the customer classes associated with individual DSM programs, consistent with the method for allocating the direct program DSM costs the Commission ordered in D.95-12-053. PG&E explains that as a result of the Gas Accord, the EPMC allocation factor becomes less meaningful, since the factor now only applies to customer and distribution-level marginal costs which are almost entirely allocated to the core. PG&E does not disagree with Mr. Weil's proposal stated below, but believes that the issue raised by Mr. Weil should be addressed in the Natural Gas Strategy Rulemaking, R.98-01-011, rather than here.

In its initial testimony, ORA did not object to PG&E's proposal here and TURN has no position. The BCAP Joint Testimony does not address this issue.

Mr. Weil disagrees with PG&E. Although Mr. Weil recognizes that past Commission decisions support PG&E's proposed allocation in this proceeding, he states that these decisions apply to special situations and endorse uncontested stipulations not founded on rigorous analysis. Mr. Weil believes that the Commission should adopt EPMC base revenues cost allocation for PG&E's DSM common and program costs. Mr. Weil argues that all utility customers and society overall generally benefit from reduced system demand, and that nonparticipating customers within individual customer classes do not receive any DSM benefits beyond those delivered to all customers generally. Mr. Weil believes that the Commission should address this issue now, even if it might again address the issue in proceedings arising from the Natural Gas Strategy Rulemaking.

CIG/CMA oppose Mr. Weil's proposal. They believe that it is unfair and not consistent with the policy established in PG&E's last BCAP, D.95-12-053. CIG/CMA believe that if the Commission is going to reconsider its policy at all, it should be done in the context of a generic proceeding such as the Natural Gas Strategy Rulemaking.

The Commission's practice of allocation to program target classes originated in D.93-12-043, issued in SoCalGas' general rate case. In that case, the Commission determined that the costs of a specific program that offered consulting services to noncore customers should not be assigned to the core. For consistency, the Commission allocated to core customers the costs of core DSM programs. (See D.93-12-043, 52 CPUC2d 471, 538.) In D.94-12-052, issued in a test year 1994 BCAP for SoCalGas, the joint recommendation adopted ORA's position that marketing costs, which include DSM, should be assigned to customers for whom the costs are incurred. (See 58 CPUC2d 306, 315.) This element of the joint recommendation was uncontested. However, in another part of the decision addressing an issue contested by TURN, the Commission found that SoCalGas correctly complied with D.93-12-043 in allocating the costs of DSM programs to its core customers. (See 58 CPUC2d at 341.) In PG&E's last BCAP, D.95-12-053, the Commission denied PG&E's requested allocation of DSM costs by EMPC, finding that marketing and DSM costs should be directly assigned to the customer classes for whom the programs are designed. In D.97-06-108, issued in our electric industry restructuring proceeding (R.94-04-031 / Investigation (I.) 94-04-032), the Commission stated that the "Natural Gas Strategy proceeding is the forum for considering the appropriate allocation of gas public purpose program costs across customer groups." (D.97-06-108, slip op. at p. 8, Finding of Fact 6.)

We adopt PG&E's proposal, since it is consistent with our previously established precedent. We do so without prejudice to any party to raise a different allocation method in other Commission proceedings where this issue may be appropriately raised.

24. The Electric Generator Joint Testimony

24.1. The Contested Issues

As discussed above, PG&E also sponsored a separate set of joint testimony with EGC and the City of Redding (Exhibit 8), which we refer to as the Electric Generator Joint Testimony. This joint testimony resolves three inter-related outstanding issues among these parties that address the appropriate transportation rate for various electric generators. This joint testimony is supported by all parties that have taken an active role on these issues in this proceeding, and does not impact the gas rates of other customer classes.

The first issue is PG&E's initial proposal to keep divested power plants under the same rate schedule as PG&E-owned gas-fired power plants. Before the commencement of electric industry restructuring, PG&E's UEG class had been composed entirely of PG&E-owned gas-fired electric generating plants. As a result of electric industry restructuring, PG&E is divesting or planning to divest all remaining UEG plants during the 1998 BCAP period. In its initial testimony, PG&E proposed to continue serving divested power plants under the same rate schedule as PG&E-owned gas-fired power plants. The ECG did not necessarily oppose this proposal, but believed it is only a partial solution to the issues concerning gas transportation rates for electric generators. ECG therefore made its proposal discussed below as the "third issue."

The second issue involves the City of Redding's proposal. In its initial testimony in response to PG&E's filing, the City of Redding proposed to serve municipally owned electric generation facilities at the same rates which currently apply to PG&E-owned power plants and cogenerators. The City of Redding states that such facilities perform the same function (i.e., electric generation), have the same principal operating characteristics and load profiles, and are served at the same transmission level of service as utility-owned plants.

In response to the City of Redding, PG&E expressed concern that City of Redding's proposal, among other things, (a) would increase inter-class subsidies if distribution-level municipal load is subsidized by transmission-level UEG load; (b) fails to address how differences in the costs to serve, such as access charges, of municipal generation customers would be recovered; and (c) does not specify if other governmentally owned generation plants would be treated as municipal load. PG&E also expressed concern that City of Redding's proposal would shift CARE and public purpose program costs previously collected from municipal electric generation customers to core and industrial customers.

The third issue involves EGC's proposal. In its initial testimony in response to PG&E's filing, EGC proposed to include all electricity generators in PG&E's service territory - - including PG&E-owned plants, divested plants, municipally owned plants, congenerators, new independent power producers and solar thermal electric generators - - in a single rate class and charge them all the same rate. EGC reasons that the changes in the electric market as a result of electric industry restructuring, where there are many more competitors generating electricity, will eliminate the reason to continue today's disparate treatment of gas-fired electric generators in PG&E's gas rate design. EGC states that in the near future, all gas-fired electric generators will be similarly situated in the market, and should all face the same cost allocation and rate design for their gas service. EGC reasons that a single electric generation class will allow all gas-fired generators to compete on the basis of the efficiency with which they can produce power, without distortions in that competition caused by differences in gas rate design that no longer make sense in the new electric market.

PG&E agrees with the basic tenet that changing industry structure requires rethinking policy and structure for gas ratemaking applicable to gas-based electric generators. However, because it believes these issues need to be placed in the broader context of industry restructuring in general, PG&E opposes addressing them in this BCAP, but rather believes these issues are more appropriately addressed in the Natural Gas Strategy Rulemaking, R.98-01-011. In its rebuttal testimony, PG&E also argues that a single generator class proposal would lump anyone using gas to produce electricity into one class, despite disparate costs to serve. At this point, PG&E states it does not have the data and has not performed the studies to identify the shifting customer and distribution-level costs that would be involved. Nor has PG&E performed the study to determine the scaled marginal customer and distribution-level marginal costs to serve the customers who would compose the single electric generator class, as proposed by EGC. PG&E also expressed concerns regarding the expansion of the level of interclass cost subsidies. PG&E reasoned that establishing a single electric generator class with no regard to incremental heat rate would contribute to a drop in the efficiency of new generation units installed, since the presumably lower cost of gas would reduce the incentive for owners of new units to pay higher capital costs for the most efficient engine.

24.2. The Compromise

The Electric Generator Joint Testimony presents a compromise among PG&E, ECG, and the City of Redding regarding the three contested issues discussed above. The joint testimony resolves, for purposes of this proceeding only, all the issues raised by PG&E, EGC, and the City of Redding. All parties further reserve their rights to pursue such issues in the Natural Gas Strategy Rulemaking, R.98-01-011.

The joint testimony provides that PG&E's gas-fired electric generation plants, PG&E's divested gas-fired electric generation plants, and transmission-level loads serving the electric generation of municipally owned electric generation facilities should be included in the EG class.[7] In the joint testimony, the joining parties also agree to the annual reallocation of a sum of dollars to the EG class, multiplied by 50 million annual therms. As a result of this cost reallocation, the stipulation will have no rate impact on core, industrial or

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[7] For purposes of the joint testimony, municipally owned electric generation facilities include "gas fired electric generation facilities owned by municipalities, irrigation districts under California law (ID), Joint Power Authorities under California law (JPAs), or other California state or local governmental entities; provided however, that 'municipally-owned electric generation plants' do not include cogeneration facilities owned by municipalities, IDs, JPAs, other California state or local governmental entities." (Exhibit 8 at pp. 2-3.)

wholesale customers. The joint testimony also provides that, for purposes of setting the cogeneration and solar electric generation parity rate for this BCAP only, the calculation of parity is to include the adopted costs and throughput for EG class as set forth in the joint testimony and figures implementing it. ORA does not oppose the joint testimony since there is no impact on core, industrial, or wholesale customers as a result of the resolution of these issues. No other party objects to this joint testimony.

The Electric Generator Joint Testimony is a reasonable compromise of these three disputed issues and we adopt it, subject to our modification below on the withdrawal of testimony. The Commission has recently instituted its Natural Gas Strategy Rulemaking, and is now in the process of scoping the issues and calling for more detailed input from the parties. This PG&E BCAP falls during a transition period. This compromise, which assesses many of the existing electricity generators in PG&E's service territory the same volumetric transportation rate, is a reasonable interim solution until these issues can be more fully addressed in our gas strategy rulemaking or other appropriate proceeding. This compromise limits municipal load eligibility for the EG schedule to transmission-level load, and prevents distribution-level loads from shifting to the EG class. PG&E has stated that distribution-level loads have a higher cost to serve. We are also influenced by the fact that the joining parties have resolved their differences with no rate impact on core, industrial, or wholesale customers, and have therefore resolved these issues in a manner that does not negatively impact any other party to the proceeding.

We modify the joint testimony in one minor respect. The joint testimony provides that the parties may withdraw certain portions of their testimony from the record. Rather, at the evidentiary hearings, we received into evidence all the parties' original testimony as exhibits herein, as well as the

Electric Generator Joint Testimony. We recognize that the Electric Generator Joint Testimony modifies the parties' other related testimony for this proceeding, but do not agree to withdraw any of the testimony.

PG&E has also proposed 100% volumetric transportation and customer access charge rates for the new EG class created under the Electric Generator Joint Testimony proposal, which no party opposes. We adopt this proposal.

25. The Filing Date for PG&E's Next BCAP Application

The parties did not address the issue of the filing date for PG&E's next BCAP application. However, we believe it is appropriate that we give direction on this issue here because the parties unanimously agreed to suspend the schedule to await the Commission's decision in the Gas Accord application. Since portions of the joint testimony assume a two-year BCAP period, this decision directs PG&E to file its next BCAP application no later than October 29, 1999, allowing the rates adopted in this decision to be in effect for two years.

26. Comments on the Proposed Decision

Pursuant to Public Utilities Code § 311, the Proposed Decision of ALJ Econome was published on May 18, 1998. We received comments and replies from PG&E, ORA, City of Redding, ECG, TURN and Weil. Additionally, PG&E served late-filed Exhibit 25 with its opening comments. This Exhibit is an update to the BCAP tables (see Appendix B) to reflect the outcome of the proposed decision, current balancing account information, and approved regulatory changes which have gone into effect after PG&E's previous updates.

In response to the parties' comments, we have made changes to the proposed decision as set forth below. We have also made other minor changes to improve the discussion, add references to the record, and correct typographical errors.

- We decline TURN's invitation to revisit what we have stated in the Gas Accord decision in this proceeding with respect to the CPIM. (See Section 21.)

- We add the clarification that we adopt PG&E's uncontested proposal for 100% volumetric transportation and customer access charge rates for the new EG class created under the Electric Generator Joint Testimony. (See Section 24.)

- We adopt some technical corrections to Sections 19 and 23 offered by Mr. Weil's comments, which do not change the outcome set forth in the proposed decision.

- We make changes to the tables set forth in Appendix B to reflect PG&E's updated filing in Exhibit 25.

In its reply comments, TURN requests that the three attachments to PG&E's opening comments be stricken because (1) PG&E did not produce them during the proceeding, and (2) as a result of the attachments, PG&E's comments exceed the 15 page limit for opening comments as set forth in Rule 77.3. Excluding the attachments, PG&E's opening comments are nine pages in length.

The attachments to PG&E's opening comments include copies of material filed with the Commission regarding the Gas Accord proceeding. Specifically, the attachments include TURN's comments on issues raised at the second workshop, TURN's comments on the alternate order of Commissioners Bilas and Neeper, and PG&E's supplemental report describing the post-1997 core procurement incentive mechanism. PG&E cites to these various documents in its opening comments, and presumably provides actual copies of filed material to which it cites for the Commission's convenience in reviewing the statements made in PG&E's opening comments. Because the attachments do not include additional argument, but are excerpts from material filed with the Commission in another proceeding to which PG&E makes specific reference in its opening comments, we deny TURN's request to strike the attachments to PG&E's opening comments.

Findings of Fact

1. PG&E filed its BCAP application on March 3, 1997. PG&E's initial application sought to establish gas rates for a two-year test period, from January 1, 1998, through December 31, 1999. Most of the parties' revised testimony and the joint testimony assumed a BCAP test-year period from September 1, 1998 through August 31, 2000.

2. President Bilas issued an April 17, 1997, ruling identifying this application as a candidate proceeding to be processed under the Commission's experimental rules implementing SB 960. The ruling categorized this proceeding as "ratesetting" as defined by Experimental Rule 1.d.

3. The Commission's final rules implementing SB 960 apply to this proceeding after January 1, 1998. (See Rule 4 (b)(1).)

4. The April 17, 1997 ruling granted ORA's motion to temporarily suspend the rate case plan procedural schedule pending the issuance of a Commission decision in the pending Gas Accord Application.

5. On August 1, 1997, the Commission issued D.97-08-055, the Gas Accord decision. The October 6, 1997 ruling and scoping memo issued after the second prehearing conference in this proceeding designated ALJ Econome as the principal hearing officer pursuant to the Commission's final rules implementing SB 960 after January 1, 1998, and set forth a schedule under which the Commission should issue a decision in this matter no earlier than 30 days after the issuance of the proposed decision, assuming a submission date of March 13, 1998, and the issuance of the proposed decision by June 11, 1998..

6. At the next prehearing conference on February 2, 1998, many, but not all, of the active parties stated that they were able to join in a stipulation and joint

testimony, and had served this joint testimony prior to the prehearing conference.

7. Evidentiary hearings were held before ALJ Econome on February 3 and 4, 1998. The parties waived closing argument before President Bilas. No party requested final oral argument before the Commission pursuant to Rule 8(d) within the time specified by the scoping memo or at any other time.

8. The parties filed opening briefs on February 27, 1998 and reply briefs on March 13, 1998, after which the matter was submitted.

9. Because the average temperatures in PG&E's service territory have been increasing over time, it is reasonable to make a downward adjustment to the number of HDDs assumed to represent an "average" temperature year for the purposes of forecasting throughput for this proceeding.

10. Further study is needed to identify ways to develop a common methodology to forecast temperature conditions in future proceedings.

11. Adoption of the BCAP Joint Testimony on the issue of the amortization of the CFCA is expected to reduce the balance in the CFCA to a reasonable level.

12. TURN's proposal, adopted by the BCAP Joint Testimony, to allocate the balance in the EOR Balance Account using the EPMC allocation adopted in PG&E's last BCAP, D.95-12-053, ensures that the undercollection in this account is refunded in the same manner in which it was collected.

13. ORA's proposal regarding the ITCS account, which is adopted by the BCAP Joint Testimony, and which recommends that the ITCS balance be transferred to the CFCA, and that PG&E update the balances for both the core and noncore ITCS accounts through February 28, 1998, to reflect the Gas Accord's March 1, 1998 implementation date, is an administratively simple and equitable treatment for this account.

14. TURN's two proposed adjustments to customer accounts costs, which are adopted in the BCAP Joint testimony, treat these costs consistent with PG&E's last BCAP decision, D.95-12-053.

15. Under the BCAP Joint Testimony's provision adopting PG&E's agreement to provide noncore customers who would be reclassified to core under PG&E's proposed change to noncore eligibility standards written notice that the ALJ's proposed decision adopted PG&E's proposed change to noncore eligibility, the notice should be in sufficient time for affected parties to examine their usage in light of the new rules.

16. TURN's proposal regarding the allocation of CARE A&G credits, adopted by the BCAP Joint Testimony, closely approximates the way costs would show up in the customer accounts expense and is consistent with the last BCAP decision, D.95-12-053.

17. The BCAP Joint Testimony's two-tiered declining block rate design proposal for the commercial classes, with the first block ending at 4000 therms instead of 2000 therms, addresses the rate cliff problem identified by PG&E without adversely impacting lower volume customers.

18. The BCAP Joint Testimony's 10% core deaveraging proposal in the second year of the BCAP will result in a more orderly transition toward deaveraged rates.

19. The BCAP Joint Testimony's adoption of a reduction in customer access charge for small commercial customers with less than 1000 therms annual usage from $13.42 per month to $10.50 per month at the beginning of the second year of the BCAP better reflects the costs of serving small commercial customers, and ensures that these customers receive the benefits from the core deaveraging proposal.

20. There are legitimate conflicting opinions about whether the Gas Accord was specific about distribution costs allocable to large customers.

21. The BCAP Joint Testimony, adopting a compromise on the disposition of the balance of the Market Center Account, addresses a one-time issue specific to this BCAP.

22. PG&E states that Wild Goose's statement of position seeking that the Commission direct PG&E's core procurement department to exercise all due diligence as a storage customer to maximize the value of its storage capacity on behalf of ratepayers, is consistent with PG&E's Core Procurement Department's position on minimizing overall gas costs.

23. The BCAP Joint Testimony adopts replacement frequencies of 1.06%, 3.29%, and 2.56%, respectively, for services, regulators, and meters.

24. The BCAP Joint Testimony's provision to defer the issue of allocating the BCA balance until the next cost allocation proceeding is not contrary to Resolution G-3288.

25. It is reasonable to decide the cost allocation issue for the BCA balance after, and not before, information on cost allocation is obtained.

26. We wish PG&E to abide by its assurances that PG&E's core procurement department will attempt to broker excess intrastate core capacity, if that results in a lower overall cost of gas to the core.

27. No party presented testimony contesting PG&E's procurement revenue requirement.

28. In D.97-06-108, slip op. at p. 8, Finding of Fact 6, we stated that the "Natural Gas Strategy proceeding is the forum for considering the appropriate allocation of gas public purpose program costs across customer groups."

29. PG&E's recommendation that common costs allocated to DSM programs be directly allocated to the customer classes associated with individual DSM

programs is consistent with the method for allocating the direct program DSM costs as ordered by the Commission in D.95-12-053, as well as in other proceedings.

30. The Electric Generators Joint Testimony provides that PG&E's gas-fired electric generation plants, PG&E's divested gas-fired electric generation plants, and transmission-level loads serving the electric generation of municipally owned electric generation facilities should be included in the EG class, as well as an annual reallocation of a sum of dollars to the EG class, multiplied by 50 million annual therms, so that the stipulation will have no rate impact to core, industrial or wholesale customers. The joint testimony also provides that, for purposes of setting the cogeneration and solar electric generation parity rate for this BCAP only, the calculation of parity is to include the adopted costs and throughput for EG class as set forth in the joint testimony and figures implementing it.

Conclusions of Law

1. Exhibits 7, 8, and the oral stipulation of PG&E and TURN should be treated as joint testimony, since the parties did not present their stipulation and joint testimony in compliance with the Commission's settlement rules.

2. We are not bound to adopt the joint testimony as an indivisible whole.

3. TURN's throughput proposal, adopted at Section II A of the BCAP Joint Testimony, is reasonable and should be adopted because it should better reflect PG&E's actual throughput during the BCAP period.

4. We adopt the BCAP Joint Testimony's recommendation at Section II B that TURN's proposed MDMs, as corrected by Mr. Aslin of PG&E and shown on Table 1A of Mr. Aslin's rebuttal testimony (Exhibit 3), are reasonable to use in this proceeding.

5. We adopt the BCAP's Joint Testimony recommendation at Section II, as modified here, that no later than six months prior to the date PG&E files its next BCAP or other type of proceeding which may serve similar functions in the future, PG&E shall convene a workshop open to all interested parties to address the need to identify ways to develop a common methodology to forecast temperature conditions in future proceedings. PG&E should give advance notice of this workshop to, inter alia, the parties on the service list of this proceeding.

6. Section III of the BCAP Joint Testimony providing that PG&E should amortize the revision date balance over a 12-month period with no forecasted interest, assuming the "revision date balance" is the forecasted balance for the month end immediately preceding the BCAP rate change, is reasonable and we adopt it, since it is expected to reduce the existing balance in the CFCA to a reasonable level.

7. Section IV of the BCAP Joint Testimony adopting ORA's position on the issue of the storage transition cost subaccount, as more fully set forth in Exhibit 12, pages 4-6 to 4-8, is reasonable and we adopt it.

8. We adopt the proposal at Section IV of BCAP Joint Testimony that at a future date, ORA should audit the final balance in the storage transition cost subaccount to ensure proper accounting. We modify the BCAP Joint Testimony to direct that ORA complete this audit no later than 60 days prior to the date when PG&E files its next BCAP application, or by August 30, 1999.

9. Section V of the BCAP Joint Testimony, allocating the balance in the EOR Balance Account using the EPMC allocation adopted in D.95-12-053, is reasonable and we adopt it. We also adopt PG&E's proposal to allocate the forecast period EOR revenue credit on a going-forward basis by an equal percentage of marginal distribution cost allocation.

10. Section VI of the BCAP Joint Testimony, adopting ORA's recommendation for treatment of the ITCS Account, is reasonable and we adopt it.

11. PG&E's rebuttal testimony regarding Transwestern Pipeline demand charges, adopted by Section VII of the BCAP Joint Testimony, which proposal makes no change to the accounting for Transwestern capacity credits, is equitable and we adopt it.

12. Section VIII of the BCAP Joint Testimony, adopting TURN's two adjustments to customer account charges, is reasonable and we adopt it.

13. PG&E's proposed changes to the noncore eligibility standards, as well as Section IX of the BCAP Joint Testimony, requiring PG&E to send notice to noncore customers who would be reclassified to core, are reasonable and we adopt them. PG&E is required to mail such written notice to affected parties no later than seven days after the mailing of the ALJ's proposed decision in this case.

14. Section X of the BCAP Joint Testimony, adopting TURN's proposal regarding the allocation of CARE A&G credits, consistent with the result in the last BCAP, D.95-12-053, is reasonable and we adopt it.

15. Section XI A of the BCAP Joint Testimony, adopting a two-tiered block rate design for the commercial classes is reasonable because it addresses the rate cliff problem identified by PG&E without adversely impacting lower volume customers, and we adopt it.

16. Section XI B of the BCAP Joint Testimony, adopting a 10% core deaveraging rate in the second year of the BCAP, is reasonable because it will result in a more orderly transition to deaveraged rates, and we adopt it.

17. Section XI B of the BCAP Joint Testimony, adopting a reduction in customer access charge for small commercial customers with less than 1000 therms annual usage from $13.42 per month to $10.50 per month at the beginning

of the second year of the BCAP, is reasonable because it better reflects the costs of serving small commercial customers, and ensures that these customers receive the benefits from the core deaveraging proposal. We therefore adopt Section XI B of the BCAP Joint Testimony.

18. Section XII of the BCAP Joint Testimony, reaching a compromise on the distribution costs allocable to large distribution customers, is reasonable given the legitimate conflicting opinions about whether the Gas Accord was specific about distribution costs allocable to large customers, and we adopt it.

19. Section XIII of the BCAP Joint Testimony, adopting PG&E's unopposed position on the issue of pipeline demand charge allocation, is reasonable and we adopt it.

20. Section XIV of the BCAP Joint Testimony, adopting a compromise on the disposition of the balance of the Market Center Account, is reasonable in light of both the information PG&E provided in rebuttal regarding the operation of PG&E's market center and the litigation risks associated with the various proposals, and we adopt it.

21. PG&E should exercise all due diligence in brokering excess core capacity on the core's behalf and should use only any remaining capacity in offering market center services.

22. Section XV of the BCAP Joint Testimony, adopting replacement frequencies of 1.06%, 3.29%, and 2.56%, respectively, for services, regulators, and meters, is reasonable and we adopt it.

23. Section XVI of the BCAP Joint Testimony, adopting computational corrections made by Mr. Weil to the calculation of franchise fees and uncollectibles, is reasonable and we adopt it, because appropriate corrections should be included in this decision.

24. Section XVII of the BCAP Joint Testimony, providing that PG&E will track gas imbalance cash transactions by core and noncore classes, and deferring allocation of the BCA to the next cost allocation proceeding, is reasonable, and we adopt it, because it is reasonable to defer this issue until we have data to determine the best allocation method.

25. Mr. Weil's proposal regarding the BCA account should be denied.

26. PG&E and TURN's oral stipulation that the issue of the allocation of UEG metering costs should be deferred to the first BCAP after the expiration of the Gas Accord, which no other party opposes, is reasonable and we adopt it, with the clarification that the issue be deferred to the first BCAP after the expiration of the Gas Accord, or other similar type of proceeding which may serve a similar function in the future.

27. We decline TURN's invitation in this proceeding to revisit what we have stated in the Gas Accord decision, D.97-08-055, with respect to the CPIM.

28. PG&E should use its best efforts in attempting to market unused core intrastate capacity in order to mitigate the cost of excess capacity for the core.

29. PG&E's showing on the procurement revenue requirement is reasonable for the limited purposes that a procurement revenue requirement is needed in this case, and we adopt it for these limited purposes.

30. We adopt PG&E's recommendation that common costs allocated to DSM programs be directly allocated to the customer classes associated with individual DSM programs. In this case, such costs should be allocated to PG&E's core customers.

31. The Electric Generator Joint Testimony is a reasonable interim solution addressing the issues raised by the joining parties because it assesses many of the existing electricity generators in PG&E's service territory the same volumetric transportation rate until these issues can be more fully addressed in our Natural

Gas Strategy Rulemaking or other appropriate proceeding, and it resolves the parties' differences with no rate impact to the core, industrial, or wholesale customers. The Electric Generator Joint Testimony should be adopted, with the clarification that none of the parties' testimony is withdrawn, but with the recognition that the Electric Generator Joint Testimony modifies the parties' previous testimony in this proceeding.

32. PG&E's proposal for 100% volumetric transportation and customer access charge rates for the new EG class created under the Electric Generator Joint Testimony is approved.

33. Since portions of the parties' joint testimony assume a two-year BCAP period, PG&E should file its next BCAP application no later than October 30, 1999, allowing the rates adopted in this decision to be in effect for two years.

34. TURN's request to strike the attachments to PG&E's opening comments is denied.

35. Because this decision resolves the outstanding issues in this proceeding, the proceeding should be closed.

O R D E R

IT IS ORDERED that:

1. The Biennial Cost Allocation Proceeding (BCAP) Joint Testimony and the Electric Generators Joint Testimony are adopted as modified by the discussion, findings of fact, and conclusions of law in this decision.

2. Pacific Gas & Electric Company (PG&E) shall file, on or after the effective date of this order, and at least 25 days prior to their effective dates, revised tariff schedules which implement the adopted changes shown in Appendix B, which incorporates the relevant findings and conclusions of this decision.

3. The revised tariff schedules shall become effective on or after September 1, 1998, and shall comply with General Order 96-A. The revised tariffs shall apply to service rendered on or after their effective dates.

4. Unless otherwise directed, PG&E shall file its next BCAP application on October 29, 1999.

5. No later than six months prior to the date PG&E files its next BCAP or other type of proceeding which may serve similar functions in the future, PG&E shall convene a workshop open to all interested parties to address the need to identify ways to develop a common methodology to forecast temperature conditions in future proceedings. PG&E shall give advance notice of this workshop to, inter alia, the parties on the service list of this proceeding.

6. The Office of Ratepayer Advocates shall complete its audit of the final balance in the storage transition cost subaccount, to ensure proper accounting, no later than sixty days prior to the date when PG&E files its next BCAP application, or by August 30, 1999.

7. No later than 60 days prior to the beginning of the second year of the BCAP, or July 2, 1999, PG&E shall file an advice letter with workpapers, served on all parties to this proceeding, to implement the change in commercial customer class charge adopted in this proceeding.

8. Application 97-03-002 is closed.

This order is effective today.

Dated June 18, 1998, at San Francisco, California.

RICHARD A. BILAS
President
P. GREGORY CONLON
JESSIE J. KNIGHT, JR.
HENRY M. DUQUE
JOSIAH L. NEEPER
Commissioners

APPENDIX A

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(END OF APPENDIX A)

APPENDIX B

APPENDIX B - TABLE 1

PACIFIC GAS AND ELECTRIC COMPANY

1998 BCAP A. 97-03-002

TOTAL REVENUE REQUIREMENT (Revised for Trueup & Accord Decisions)

PERIOD: JANUARY 1, 1998 THROUGH DECEMBER 31, 1999*

$(000)

Line No.		TOTAL PERIOD	ANNUAL	Line No.
	PROCUREMENT REVENUE REQUIREMENT			
1	**Gas Supply Portfolio Costs:**			1
2	Sales Commodity Costs	$793,623	$396,811	2
3	Shrinkage Commodity Costs	$47,627	$23,813	3
4	**Capacity Costs:**			4
5	PGT Capacity Costs	$71,929	$35,964	5
6	Canadian Capacity Costs	$60,388	$30,194	6
7	Intrastate Capacity Costs	57,890	$28,945	7
8	Carrying Cost on Cycled Gas in Storage	$2,329	$1,165	8
9	**Total Forecast Period Costs**	$1,033,786	$516,893	9
10	Procurement Account Balances	$29,192	$14,596	10
11	Franchise Fees and Uncollectible Accounts Expense	$12,419	$6,210	11
12	Brokerage Fees	$11,533	$5,767	12
13	**Total Procurement Revenue Requirement**	$1,086,929	$543,466	13
14	Less Procurement Revenues at Present Rates	$1,099,393	$549,697	14
15	**Change In Procurement Revenue Requirement**	($12,464)	($6,231)	15
16				16
17				17
18	**TRANSPORTATION REVENUE REQUIREMENT**			18
19				19
20	Base Revenue Amount (incl. F&U)			20
21	Distribution	$1,525,912	$762,956	21
22	Public Purpose Program	$73,020	$36,510	22
23	Storage (reserved for Core)	$71,388	$35,694	23
24	EOR Credit	($49)	($25)	24
25	CARE A&G Credit	($1,155)	($577)	25
26	Brokerage Fee Credit	($11,533)	($5,767)	26
27	Customer Access Charge - Distribution	($11,316)	($5,658)	27
28	Carrying Cost on Noncycled Gas in Storage	$8,100	$4,050	28
29	NGV Expenses	$11,555	$5,778	29
30	CARE A&G Expenses	$1,155	$577	30
31	CPUC Fee Expenses	$8,475	$4,238	31
32	CEE Shareholder Incentive**	$4,278	$2,139	32
33	**Total Forecast Period Costs**	$1,679,830	$839,915	33
34	Transportation Account Balances	$174,541	$87,271	34
35	Franchise Fees and Uncollectible Accounts Expense	$4,286	$2,143	35
36	**Total Transportation Revenue Requirement**	$1,858,657	$929,329	36
37	Less Transportation Revenues at Present Rates	$2,041,515	$1,020,758	37
38	**Change In Transportation Revenue Requirement**	($182,858)	($91,430)	38
39				39
40	**Total Change In Revenue Requirement**	($195,322)	($97,661)	40

*Period coincides with the throughput agreed upon in the joint testimony for the BCAP period

**Includes impact of Annual Earnings Assessment Proceeding D.98-03-063

APPENDIX B - TABLE 2

PACIFIC GAS AND ELECTRIC COMPANY

1998 BCAP A. 97-03-002

BALANCING ACCOUNT SUMMARY (Revised for Trueup & Accord Decisions)

$(000)

Line No.		PROCUREMENT BALANCING ACCOUNTS	Forecasted Balances for 8/31/98	Line No.
1		PGA: Core Subaccount	$0	1
2		Core Shrinkage Subaccount	$0	2
3		Core Canadian Demand Charge Subaccount	$29,192	3
4		Core-subscription Subaccount	$0	4
5		Standby Service Subaccount	$0	5
6		Procurement Take-or-Pay Subaccount	$0	6
7		Core Demand Charge Subaccount of CPDCA	$0	7
8		Sum of Procurement Accounts	$29,192	8
9				9
10				10
11		TRANSPORTATION BALANCING ACCOUNTS		11
12				12
13	(*)	Core Fixed Cost Account	$138,291	13
14		Noncore Fixed Cost Account	$2,092	14
15		Core Brokerage Fee Balancing Account	$667	15
16		Noncore Brokerage Fee Balancing Account	$384	16
17		Noncore Customer Class Charge Account	($1,840)	17
18		Enhanced Oil Recovery Account	($675)	18
19		CFA Debt Service Balancing Account	$84	19
20		CFA Expense Balancing Account	($236)	20
21		California Alternate Rates for Energy Account	$1,576	21
22		Natural Gas Vehicle Balancing Account	($1,591)	22
23	(*)	Interstate Transition Cost Surcharge Core Subaccount	($19,656)	23
24		Interstate Transition Cost Surcharge Noncore Subaccount	$24,872	24
25		Subscribed Storage Revenue Subaccount	($0)	25
26		Storage Transition Cost Subaccount	$771	26
27		Hazardous Substance Balance	$5,417	27
28		Market Center Account	($3,603)	28
29		PGT Credit Subaccount of CPDCA	($139)	29
30		Carrying Cost on Noncore Gas in Storage Trueup	$507	30
31		Carrying Cost on Gas in Subscribed Storage Trueup	$5	31
32	(*)	Core Migration Balancing Account	$27,646	32
33		Balancing Charge Account	$0	33
34		Cogeneration Distribution Shortfall Account	$0	34
35		Additional Imputed CFCA & Core ITCS for one Year Amortization		35
36		Sum of Transportation Accounts	$174,541	36

(*) The CFCA rate component includes the amount on line 13 plus the Core ITCS amount on line 23 plus 82% of the core to noncore migration shown on line 32.

APPENDIX B • TABLE 3

PACIFIC GAS AND ELECTRIC COMPANY
1998 BCAP A. 97-03-002
CLASS AVERAGE RATES ($/th) (Includes WACOG & 1998 AEAP)

Line No.	Customer Class	Gas Accord March 1, 1998 (a)	1998 BCAP Sept. 1, 1998 (b)	Change from Gas Accord (c)
	BUNDLED CORE			
1	Residential	$ 0.60041	$ 0.60417	0.6 %
2	Small Commercial	0.61822	0.60813	-1.6 %
3	Large Commercial	0.43544	0.41317	-5.1 %
	NONCORE TRANSPORT (FIRM BAJA PATH)			
4	Industrial Distribution	0.10827	0.11381	5.1 %
5	Industrial Transmission	0.04552	0.04216	-7.4 %
6	Cogeneration	0.04050	0.03449	-14.8 %
7	Generation	0.04050	0.03449	-14.8 %
8	Coalinga	0.04460	0.03761	-15.7 %
9	Palo Alto	0.04066	0.03397	-16.5 %
10	WC Gas	0.05457	0.04695	-14.0 %
11	Island Energy	0.07058	0.06094	-13.7 %

Notes and Assumptions:
(a) The Gas Accord rates are effective on March 1, 1998
(b) Core rates are bundled and include average backbone transmission, local transmission, distribution, storage, customer class charge and procurement charges.
(c) Noncore rates include backbone transmission (firm from Baja Path), local transmission, customer class charges, customer access charges and applicable distribution charges.

APPENDIX B TABLE 4

1998 BCAP A.97-03-002
GAS ACCORD PROCUREMENT RATES AND REVENUES (Includes WACOG and 1998 AEAP)
Residential/Small Commercial After De-averaged by 8 %

LINE No		CORE				CORE SUBSCRIPTION*				
		Residential	Sm Comm'l	Lg Comm'l	NGV**	Transmission	Distribution	N.C NGV	Wholesale	TOTAL
1	SALES (Mth)	3,866,430	866,750	34,480	25,570	17,260	118,330	26,780	0	4,779,660
2	Summer		290,950	17,730						
3	Winter		375,800	16,750						
4	WACOG ($/therm)	$ 16621	$ 16621	$ 16621	$ 16621	$ 16130	$ 16130	$ 16130	$ 16130	$ 16604
5	SUBTOTAL REVENUE (000's)	$646,296	$110,821	$5,731	$4,250	$2,787	$19,096	$4,642	$0	$793,623
6	Procurement Take or Pay Subaccount	0	0	0	0	0	0	0	0	0
7	CDemand Charge Subaccount of CPDCA	0	0	0	0	0	0	0	0	0
8	Standby Service Subaccount	0	0	0	0	0	0	0	0	0
9	not used, available	0	0	0	0	0	0	0	0	0
10	SUBTOTAL REVENUE (000's)	$646,296	$110,821	$5,731	$4,250	$2,787	$19,096	$4,542	$0	$793,623
11	Subtotal Component w/o WACOG ($/therm)	$ 00000	$ 00000	$ 00000	$ 00000	$ 00000	$ 00000	$ 00000	$ 00000	$ 00000
12	F&U RATE	1 23560%	1 23560%	1 23560%	1 23560%	1 23560%	1 23560%	1 23560%	1 00250%	1 23560%
13	F&U	$7,986	$1,369	$71	$53	$34	$236	$57	$0	$9,806
14	SUBTOTAL REVENUE (000's)	$654,282	$112,190	$5,802	$4,303	$2,822	$19,332	$4,700	$0	$803,429
15	WACOG and Balances(a)	$ 16826	$ 16826	$ 16826	$ 16826	$ 16329	$ 16329	$ 16329	$ 00000	$ 16809
16	INTRASTATE BACKBONE CAPACITY - GA Implemnt	$0	$0	$0	$0	$0	$0	$0	$0	$0
17	INTRASTATE BACKBONE CAPACITY	48,366	8,294	305	0	170	754	0	0	57,890
18	REVENUES - BAJA PATH WINTER RESERVATION		2,066	78						
19			$6,225	$229						
20	INTRASTATE TRANSMISSION CHARGE ($/Th) (f)	$ 01244	$ 01244	$ 00885	$ 00000	$ 00982	$ 00637	$ 00000	$ 00000	$ 01211
21	Summer		$ 00934	$ 00664						
22	Winter		$ 01484	$ 01118						
23	PGT	$60,097	$10,305	$379	$0	$211	$936	$0	$0	$71,929
24										0
25	F&U	743	127	5	0	3	12	0	0	889
26	INTERSTATE CAPACITY CHARGE COMPONENT	$60,840	$10,432	$384	$0	$213	$948	$0	$0	$72,817
27	INTERSTATE PLD COMPONENT (e)	$ 01565	$ 01565	$ 01113	$ 00000	$ 01235	$ 00801	$ 00000	$ 00000	$ 01523
28	ANG & NOVA Period Costs - GA	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	CANADIAN BALANCES	24,390	4,182	154	0	86	380	0	0	29,192
30	ANG & NOVA Period Costs	50,455	8,652	318	0	177	786	0	0	60,388
31	F&U ON CANADIAN CHARGES (000)	925	159	6	0	3	14	0	0	1,107
32	CANADIAN CHARGES INCL F&U (000)	$75,770	$12,992	$478	$0	$266	$1,181	$0	$0	$90,687
33	CANADIAN CHARGES RATE ($/th) (d)	$ 0 01949	$ 0 01949	$ 0 01386	$ 0 00000	$ 0 01539	$ 0 00997	$ 0 00000	$ 0 00000	$ 0 01897
34	BROKERAGE FEES (000's)	$9,218	$1,581	$82	$0	$65	$447	$0	$0	$11,393
35	F&U	114	20	1	0	1	6	0	0	141
36	BROKERAGE FEES INCL F&U (000's)	$9,332	$1,600	$83	$0	$66	$452	$0	$0	$11,533
37	BROKERAGE FEE RATE ($/th) (c)	$ 00240	$ 00240	$ 00240	$ 00000	$ 00382	$ 00382	$ 00000	$ 00000	$ 00241
38	SHRINKAGE REVENUE	$39,895	$6,841	$354	$262	$25	$207	$42	$0	$47,627
39	F&U ON SHRINKAGE REV (000's)	493	85	4	3	0	3	1	0	588
40	SHRINKAGE REV INCL F&U (000's)	$40,388	$6,925	$358	$266	$26	$210	$43	$0	$48,215
41	SHRINKAGE RATE ($/th) (c)	$ 01039	$ 01039	$ 01039	$ 01039	$ 00148	$ 00177	$ 00148	$ 00000	$ 01009
42	CARRYING CST CYCLED GAS IN STOR, INCL F&U	$1,966	$341	$18	$13	$0	$0	$0	$0	$2,358
43	CARRYING COST OF GAS COMPONENT ($/TH) (g)	$ 00051	$ 00051	$ 00051	$ 00051	$ 00000	$ 00000	$ 00000	$ 00000	$ 00049
44	CS PHASEOUT SURCHARGE, INCL F&U	N/A	N/A	N/A	N/A	$121	$829	$201	$0	$1,151
45	CS PHASEOUT SURCHARGE RATE ($/TH) (h)					$ 00700	$ 00700	$ 00700	$ 00000	$ 00700
46	TOTAL PROCUREMENT REVENUES	$890,966	$152,774	$7,427	$4,581	$3,683	$23,705	$4,944	$0	$1,088,081
47	PROCUREMENT RATE (a+b+c+d+e+f+g+h)	$ 22914	$ 22914	$ 21540	$ 17916	$ 21315	$ 20023	$ 17177	$ 00000	$ 23441
48	Summer		$ 22603	$ 21318						
49	Winter		$ 23154	$ 21773						

* Core subscription prices are illustrative. Actual core subscription prices will based on the higher of monthly gas price or indexed price, and noncore interstate and intrastate capacity charges

**Variable procurement costs only are allocated to NGV. Rate on Table 8 includes transportation allocation

APPENDIX B TABLE 5
PACIFIC GAS AND ELECTRIC COMPANY
1999 BCAP A. 97-03-002
Average Annual Distribution Revenue Requirement Allocated by Customer Class [includes WACOG and 1996 AEAP] *
($000)

Line No	Component	TOTAL	Residential	Small Commercial	Large Commercial	Subtotal Core	Industrial Distribution	Industrial Transmission	Cogen	Electric Gen	Coalinga	Palo Alto	WC Gas	Island Energy	Total Noncore
1	Customer	$393,368	$293,142	$94,356	$688	$388,186	$4,556	$0	$623	$0	$0	$0	$0	$0	$5,182
2	Distribution	354,688	248,565	80,006	3,822	332,395	21,061	0	1,213	0	0	0	0	0	22,293
3	Allocation of Franchise Fees	7,499	5,431	1,745	45	7,224	257	0	18	0	0	0	0	0	275
4	Allocation of Uncollectibles Expense	1,744	1,263	406	11	1,680	80	0	4	0	0	0	0	0	84
5	TOTAL with Franchise Fee & Uncollectible	$757,300	$548,400	$176,518	$4,566	$729,485	$25,956	$0	$1,859	$0	$0	$0	$0	$0	$27,815

*Marginal Cost Revenues shown here are scaled to equal distribution base revenues.

A.97-03-002 ALJ/JJJ/jva *

APPENDIX B TABLE 8
PACIFIC GAS AND ELECTRIC COMPANY
1998 BCAP A.97-03-002
Average Annual (1) Forecast Period Costs and Credits to Base Revenue; (2) Balancing Accounts; and (3) CARE Costs Allocation by Customer Class (Includes WACOO and 1998 AEAP)
($000)

Line No	Component	TOTAL	Residential	Small Commercial	Large Commercial	Subtotal Core	Industrial Distribution	Industrial Transmission	Cogen	Electric Gen	Coalinga	Palo Alto	WC Gas	Island Energy	Total Noncore
1	EOR and Interutility Revenue Credit	$ (25)	$ (17)	$ (6)	$ (0)	$ (23)	$ (1)	$ -	$ (0)	$ (0)	$ -	$ -	$ -	$ -	$ (2)
2	Gas Brokerage Proc. Cred (Noncore Brok. Fee)	-218	0	0	0	0	-18	-72	-41	-86	0	-2	0	0	-218
3	Sales/Marketing Credit (Noncore Brokerage Fee)	-41	-31	-10	0	-40	0	0	0	0	0	0	0	0	-1
4	Gas Brokerage Proc. Credit (Core Brok. Fee)	-4,636	-3,436	-1,107	-92	-4,636	0	0	0	0	0	0	0	0	0
5	Credit to Base for CARE A&G (Transfer to Forecast Period Costs)	-578	-430	-139	-1	-570	-7	0	0	-1	0	0	0	0	-8
6	Sales/Marketing Credit (Core Brokerage Fee)	-871	-649	-209	-2	-860	-10	0	0	-1	0	0	0	0	-11
7	NGV expenses	5,778	1,579	508	42	2,130	274	1,207	890	1,446	2	28	0	0	3,648
8	CEE	2,139	1,594	513	4	2,111	25	0	1	2	0	0	0	0	28
9	CFA Debt Service	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	CFA Expense	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	CPUC Fee Expense (excluding EOR)	4,236	1,541	498	41	2,079	268	1,178	230	482	0	0	0	0	2,157
12	Core Transport Interstate Transition Subaccount of CPOCA	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Carrying costs of non-cycled gas in storage (bundled)	4,050	3,024	973	52	4,050	0	0	0	0	0	0	0	0	0
14	Load Balancing Carrying Costs of Gas In Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Franchise Fee and Uncollectibles Expense	95	50	16	1	67	3	14	4	7	0	0	0	0	28
16	TOTAL: FORECAST PERIOD COSTS	$ 9,926	$ 3,149	$ 1,013	$ 44	$ 4,206	$ 522	$ 2,270	$ 938	$ 1,966	$ 2	$ 25	$ 0	$ 0	$ 5,723
17	Carrying Cost on Noncore Gas In Storage Trueup	$ 254	$ -	$ -	$ -	$ -	$ 19	$ 84	$ 48	$ 101	$ 0	$ 2	$ 0	$ 0	$ 254
18	Natural Gas Vehicle Account Balance	-795	-217	-70	-6	-293	-38	-166	-95	-199	0	-4	0	0	-502
19	CFA Expense Account Balance	-118	-52	-17	-1	-70	-9	-39	0	0	0	0	0	0	-48
20	CFA Debt Service Account Balance	42	18	8	0	25	3	14	0	0	0	0	0	0	17
21	Core Fixed Cost Acct. Bal.	141,274	104,755	33,718	2,801	141,274	0	0	0	0	0	0	0	0	0
22	Enhanced Oil Recovery Account Balance	-337	-218	-70	-7	-296	-12	-12	-8	-12	0	0	0	0	-41
23	Carrying Cost on Gas In Subscribed Storage Trueup	2	1	0	0	1	0	0	0	1	0	0	0	0	1
24	NCFC Acct. Bal.	1,046	0	0	0	0	78	346	198	415	1	8	0	0	1,046
25	Noncore Transition Cost Account Balance	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	Core Balance, ITCS	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	G-10 Procurement Allocation	714	195	83	5	263	34	149	85	179	0	3	0	0	451
28	NonCore ITCS Rate Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Noncore ITCS Balance	12,436	0	0	0	0	936	4,115	2,351	4,930	8	96	1	1	12,436
30	Core to NC Migration Shortfall	2,488	0	0	0	0	461	2,027	0	0	0	0	0	0	2,488
31	GEDA Balacning Account	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Subscribed Storage Revenue Subaccount	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33	Storage Transition Cost Subaccount	385	105	34	3	142	18	81	46	96	0	2	0	0	243
34	Noncore Customer Class Charge Account	-920	0	0	0	0	-69	-304	-174	-365	0	-7	0	0	-920
35	Hazardous Waste Balance	2,706	740	238	20	998	129	566	323	678	1	13	0	0	1,710
36	Market Center Account	-1,802	-681	-219	-14	-914	-77	-280	-187	-351	-1	-11	0	0	-887
37	Brokerage Fee Balance Acct. (NC only)	192	0	0	0	0	14	64	36	76	0	1	0	0	192
38	Backbone Memorandum Account	0	0	0	0	0	0	0	0	0	0	0	0	0	0
39	Brokerage Fee Balance Acct. (Core only)	334	247	80	7	334	0	0	0	0	0	0	0	0	0
40	Balancing Charge Account	0	0	0	0	0	0	0	0	0	0	0	0	0	0
41	Diversion/EFO Balancing Account	0	0	0	0	0	0	0	0	0	0	0	0	0	0
42	Franchise Fee and Uncollectibles Expense	2,228	1,426	459	37	1,922	28	126	49	102	0	2	0	0	306
43	TOTAL: BALANCING ACCOUNTS	$ 160,131	$ 106,320	$ 34,222	$ 2,845	$ 143,386	$ 1,516	$ 6,770	$ 2,695	$ 5,850	$ 8	$ 105	$ 2	$ 1	$ 16,745
44	CARE Subsidy	$ (10,260)	$ (10,260)	$ -	$ -	$ (10,260)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	CARE Subsidy Allocation	10,260	4,344	1,480	123	5,947	799	3,515	0	0	0	0	0	0	4,314
46	CARE A&G Allocation	577	244	83	7	335	45	198	0	0	0	0	0	0	243
47	CARE Balancing Account	788	334	114	9	457	61	270	0	0	0	0	0	0	331
48	TOTAL: CARE COSTS	$ 1,366	$ (5,339)	$ 1,677	$ 139	$ (3,522)	$ 905	$ 3,982	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,888

APPENDIX B TABLE 7

PACIFIC GAS AND ELECTRIC COMPANY
1998 BCAP A. 97-03-002
GAS ACCORD SEASONAL VOLUMETRIC RATES FOR DISTRIBUTION SERVICE CUSTOMERS
(Includes WACOG and 1998 AEAP)

Class	Rate Component	Rates ($/th) Summer	Winter	Average	Winter to Summer Ratio
Small Commercial	Distribution Only	$ 0.17373	$ 0.25835	$ 0.22031	1.49
	Total Volumetric	0.50770	0.59699	0.55803	1.18
Large Commercial	Distribution Only	0.05976	0.10188	0.07975	1.70
	Total Volumetric	0.38590	0.43282	0.40870	1.12
Industrial Distribution	Distribution Only	0.05165	0.06973	0.05967	1.35

Notes:
Rates exclude monthly customer charge.
Total volumetric includes distribution, bundled storage, backbone and local transmission, customer class charge and procurement.
Commercial rates are average of Tier A and Tier B.

APPENDIX B - TABLE 8
PACIFIC GAS AND ELECTRIC COMPANY

1998 BCAP A.97-03-002

1998 Gas Accord Rates (Average) Components ($/Dth) (Includes WACOG and 1998 AEAP

Line No.	After Core de-averaging by 8 %	Distribution-level Service: Res.	Distribution-level Service: Sml Com.	Distribution-level Service: Lg Comm.	Industrial Distribution (Firm Baja)	Transmission-level Service: Industrial Transmission (Firm Baja)	Cogeneration (Firm Baja)	Electric Gen. (Firm Baja)	Coalinga (Firm Baja)	Palo Alto (Firm Baja)	WC Gas (Firm Baja)	Island Energy (Firm Baja)
1	Intrastate Backbone Transmission	$ 0.1244	$ 0.1244	$ 0.0885	$ 0.1557	$ 0.1557	$ 0.1557	$ 0.1557	$ 0.1557	$ 0.1557	$ 0.1557	$ 0.1557
2	Intrastate Local Transmission	0.2602	0.2602	0.2602	0.1346	0.1346	0.1346	0.1348	0.1346	0.1346	0.1348	0.1346
3	Customer Class Charge	0.6315	0.6835	0.7699	0.1113	0.1012	0.0477	0.0477	0.0359	0.0361	0.0355	0.0357
4	Customer Access Charge/Customer Charge	0.0000	0.5010	0.0447	0.1399	0.0301	0.0069	0.0069	0.0499	0.0133	0.1437	0.2834
5	Distribution	2.7041	2.2031	0.7975	0.5967	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
6	Storage, Bundled	0.1311	0.1311	0.1008								
7	Procurement, less Intra and Interstate PLD	2.0105	2.0105	1.9542								
8	Interstate Pipeline Demand Charge	0.1565	0.1565	0.1113								
9	Accord Total				$ 1.1381	$ 0.4216	$ 0.3449	$ 0.3449	$ 0.3761	$ 0.3397	$ 0.4695	$ 0.6094

1 - Intrastate backbone transmission rate components for noncore are firm from Baja path and core costs are based on a forecast of total cost from all transmission paths.
The charges to core are allocated based on average year January throughput.
2 - The local transmission rate components are from the Gas Accord Settlement Agreement Table 13.
3 - Based on 8/31/98 revision date balancing account forecast.
4 - Customer access charge rate components are from The Gas Accord Settlement Agreement Table 15. The cost per decatherm are based on the expected annual usage.
5 - Distribution is based on Joint Testimony MOM's, throughput and LRMC. Distribution revenue requirement is based on the Gas Accord Settlement Agreement, adjusted for the 1998 cost of capital decision.
6-The storage costs are based on expected annual usage.
7-From procurement rate discussed in Section 8D
8-From procurement rate discussed in Section 8D.
9-Total core rate assumes all core takes procurement service. See Table 10 for bundled core and core transport rates.

APPENDIX B TABLE 9

PACIFIC GAS AND ELECTRIC COMPANY
1998 BCAP A. 97-03-002

NGV RATES AND REVENUES (Includes WACOG and 1998 AEAP)

Line No.	Rate Class	GAS ACCORD RATES & REVENUES March 1, 1998 Adjusted for 98 BCAP WACOG			PROPOSED RATES & REVENUES W/98 BCAP Implementation			PROPOSED CHANGE IN RATES Change	
		Adj Billing Determinant # of Cust. or Mth	RATE OR CHARGE $/therm or $/cust. mo.	TEST PERIOD REVENUE $ (000)	Adj Billing Determinant # of Cust. or Mth	RATE OR CHARGE $/therm or $/cust. mo.	EST PERIO REVENUE $ (000)	$/therm or $/cust. mo.	%
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	G-NGV1								
1	Customer Charge	25	$13.42	$8	25	$13.42	$8	$0.00	0.00%
2	Volumetric Rate	18,020	$0.29541	$5,323	18,020	$0.33188	$5,980	$0.03646	12.34%
3	Total	18,020	$0.29585	$5,331	18,020	$0.33232	$5,988	$0.03646	12.32%
	G-NGV2								
4	Customer Charge	10	$13.42	$3	10	$13.42	$3	$0.00	0.00%
5	Volumetric Rate	7,550	$0.77811	$5,875	7,550	$0.81458	$6,150	$0.03646	4.69%
6	Total	7,550	$0.77855	$5,878	7,550	$0.81502	$6,153	$0.03646	4.68%
7	Total Core NGV	25,570	$0.43838	$11,209	25,570	$0.47484	$12,142	$0.03646	8.32%

APPENDIX B TABLE 1B
PACIFIC GAS AND ELECTRIC COMPANY
1998 BCAP A. 97-03-002

Core Rates and Revenues Under the Gas Accord Structure
(Includes WACOG and 1998 AEAP)

Line No.	RATE CLASS	GAS ACCORD RATES & REVENUES March 1, 1998 Adjusted for 98 BCAP WACOG: ADJ BILLING DETERMINANT Mth or # of Customers	RATE OR CHARGE $/therm or $/cust. mo.	TEST PERIOD REVENUE $ (000)	PROPOSED RATES & REVENUES W98 BCAP Implementation: ADJ BILLING DETERMINANT Mth or # of Customers	RATE OR CHARGE $/therm or $/cust. mo.	TEST PERIOD REVENUE $ (000)	PROPOSED CHANGE IN RATES $/therm or $/cust. mo.	%
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	BUNDLED RATES								
	NON-CARE RESIDENTIAL								
1	Tier I (Baseline)	2,557,418	$ 55280	$ 1,413,740	2,557,418	$ 55597	$ 1,421,847	$ 00317	0 57 %
2	Tier II	1,105,046	$ 74511	$ 823 381	1,105,046	$ 75056	$ 829,403	$ 00545	0 73 %
3	Non-CARE Subtotal	3,662,464	$ 61082	$ 2,237,121	3,662,464	$ 61468	$ 2,251,251	$ 00386	0 63 %
	CARE RESIDENTIAL								
4	Tier I (Baseline)	156,616	$ 46895	$ 73,445	156,616	$ 47062	$ 73,707	$ 00167	0 36 %
5	Tier II	63,121	$ 63191	$ 39 887	63,121	$ 63533	$ 40,103	$ 00342	0 54 %
6	CARE Subtotal	219,737	$ 51576	$ 113 332	219,737	$ 51793	$ 113 809	$ 00217	0 42 %
7	Pre-GS/GT Discount Residential Subtotal	3,882,201	$ 60544	$ 2,350,453	3 882 201	$ 60921	$ 2 365 060	$ 00378	0 62 %
8	GS and GT Discount			-$ 19 557			-$ 19 557		
9	TOTAL BUNDLED RESIDENTIAL	3,882,201	$ 60041	$ 2,330,897	3,882,201	$ 60417	$ 2 345 503	$ 00378	0 63 %
	SMALL COMMERCIAL (G-NR1)								
10	Customer Charge	103,716 6	$13.42	$ 33,406	103,716 6	$13 42	$ 33,406	$0 00	0 00 %
11	Summer Volumetric Tier A	245,705	$ 52099	$ 128,010	245,705	$ 53113	$ 130,502	$ 01014	1 95 %
12	Summer Volumetric Tier B	45,245	$ 52099	$ 23,572	45,245	$ 38047	$ 17,214	-$ 14052	-26 97 %
13	Winter Volumetric Tier A	318,920	$ 60460	$ 191,810	318,920	$ 62764	$ 198,811	$ 02304	3 81 %
14	Winter Volumetric Tier B	58,880	$ 60460	$ 35 599	58 880	$ 43203	$ 25,438	-$ 17257	-28 54 %
15	BUNDLED SML. COMM. TOT.	666,750	$ 61822	$ 412,196	666,750	$ 60813	$ 405,471	-$ 01009	-1 63 %
	LARGE COMMERCIAL (G-NR2)								
16	Customer Charge	42 6	$150.72	$ 154	42 6	$150 72	$ 154	$0 00	0 00 %
17	Summer Volumetric Tier A	2,150	$ 40878	$ 879	2,150	$ 51829	$ 1,114	$ 10951	26 79 %
18	Summer Volumetric Tier B	15,580	$ 40878	$ 6,369	15,580	$ 36763	$ 5,728	-$ 04115	-10 07 %
19	Winter Volumetric Tier A	1,250	$ 45446	$ 568	1,250	$ 61383	$ 767	$ 15937	35 07 %
20	Winter Volumetric Tier B	15,500	$ 45446	$ 7,044	15 500	$ 41823	$ 6,483	-$ 03623	-7 97 %
21	BUNDLED LRG. COMM. TOT.	34,480	$ 43544	$ 15,014	34,480	$ 41317	$ 14,246	-$ 02228	-5 12 %
22	TOTAL BUNDLED COMMERCIAL	701,230	$ 60923	$ 427,210	701,230	$ 59854	$ 419,717	-$ 01069	-1 75 %
23	TOTAL BUNDLED CORE	4,583,431	$ 60178	$ 2,758,107	4,583,431	$ 60331	$ 2,765 220	$ 00155	0 26 %
	TRANSPORT-ONLY RATES								
	NON-CARE RESIDENTIAL								
24	Tier I (Baseline)	168,658	$ 32815	$ 55,347	168,659	$ 32288	$ 54,456	-$ 00528	-1 61 %
25	Tier II	498	$ 52047	$ 259	498	$ 51747	$ 258	-$ 00300	-0 58 %
26	Non-CARE Subtotal	169,157	$ 32873	$ 55 606	169,157	$ 32345	$ 54,714	-$ 00528	-1 60 %
	CARE RESIDENTIAL								
27	Tier I (Baseline)	4,673	$ 24431	$ 1,142	4,673	$ 23752	$ 1,110	-$ 00679	-2 78 %
28	Tier II	0	$ 40726	$ 0	0	$ 40224	$ 0	-$ 00502	-1 23 %
29	CARE Subtotal	4,673	$ 24431	$ 1,142	4,673	$ 23752	$ 1,110	-$ 00679	-2 78 %
30	Pre-GS/GT Discount Residential Subtotal	173,830	$ 32646	$ 56,748	173,830	$ 32114	$ 55 824	-$ 00532	-1 63 %
31	GS and GT Discount			-$ 876			-$ 876		
32	TOTAL TRANSPORT-ONLY RES.	173,830	$ 32142	$ 55,872	173,830	$ 31610	$ 54,948	-$ 00532	-1 65 %
	SMALL COMMERCIAL (G-NR1)								
33	Customer Charge	99,368 8	$13 42	$ 32,005	99,368 8	$13 42	$ 32 005	$0 00	0 00 %
34	Summer Volumetric Tier A	249,877	$ 29834	$ 74,548	249,877	$ 30114	$ 75 249	$ 00280	0 94 %
35	Summer Volumetric Tier B	46,013	$ 29834	$ 13,727	46,013	$ 15048	$ 6,924	-$ 14786	-49 56 %
36	Winter Volumetric Tier A	289,183	$ 37829	$ 109,395	289,183	$ 39214	$ 113,401	$ 01385	3 66 %
37	Winter Volumetric Tier B	53,727	$ 37829	$ 20 324	53,727	$ 19654	$ 10,560	-$ 18175	-48 05 %
38	TRANSPORT-ONLY SML. COMM.	638,800	$ 39136	$ 250,000	638,800	$ 37279	$ 238,138	-$ 01857	-4 74 %
	LARGE COMMERCIAL (G-NR3)								
39	Customer Charge	91.4	$150.72	$ 331	91.4	$150 72	$ 331	$0 00	0 00 %
40	Summer Volumetric Tier A	4,761	$ 18760	$ 893	4,761	$ 30114	$ 1,434	$ 11354	60 52 %
41	Summer Volumetric Tier B	34,499	$ 18760	$ 6,472	34,499	$ 15048	$ 5,191	-$ 03712	-19 79 %
42	Winter Volumetric Tier A	2,589	$ 22966	$ 595	2,589	$ 39214	$ 1,015	$ 16248	70 75 %
43	Winter Volumetric Tier B	32,111	$ 22966	$ 7,375	32,111	$ 19654	$ 6,311	-$ 03312	-14 42 %
44	TRANSPORT-ONLY LRG. COMM.	73,960	$ 21180	$ 15,665	73,960	$ 19311	$ 14,282	-$ 01870	-8 83 %
45	TOT. TRANSPORT-ONLY COMM.	712,760	$ 37273	$ 265,665	712,760	$ 35415	$ 252,421	-$ 01858	-4 99 %
46	TOT. TRANSPORT-ONLY CORE	886,590	$ 36267	$ 321,538	886,590	$ 34669	$ 307,369	-$ 01598	-4 41 %
47	TOTAL RESIDENTIAL VOL. and REV.	4,056,031		$ 2,386,769	4,056,031		$ 2,400,451	$ 13,683	0 57 %
48	TOTAL COMMERCIAL VOL. and REV.	1,413,990		$ 692,876	1,413,990		$ 672,138	-$ 20,738	-2 99 %
49	TOTAL CORE VOLUMES & REVENUES	5,470,021		$ 3,079,644	5,470,021		$ 3,072,589	-$ 7,055	-0 23 %

(END OF APPENDIX B)