Decision 88-03-085 March 23, 1988 ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's motion into implementing a rate design for unbundled gas utility services consistent with policies adopted in Decision 86-03-057.	I.86-06-005 (Filed June 5, 1986)
And Related Matters.	R.86-06-006 (Filed June 5, 1986) Application 87-01-033 (Filed January 20, 1987) Application 87-01-037 (Filed January 27, 1987) Application 87-04-040 (Filed April 20, 1987)

OPINION

On December 9, 1987, we issued Decision (D.) 87-12-039 in the "implementation phase" of this proceeding. D.88-02-017 modifying D.87-12-039 was issued on February 10, 1988. The modification was a simple change of filing dates for advice letters for San Diego Gas & Electric Company.

Several applications for rehearing and petitions for modification have been filed subsequent to the December 1987 implementation order. D.88-03-041 issued March 9, 1988, resolved all of the applications for rehearing and some of the petitions for modification. The petitions for modification resolved by D.88-03-041 were:

1. Hadson Gas Systems, dated February 24, 1988;

2. Southern California Gas Company, dated February 16, 1988; and

3. Pacific Gas and Electric Company, dated January 13, 1988. (Cogeneration issue only.)

This order addresses and resolves the remaining petitions for modification of D.87-12-039, D.86-12-009, and/or D.86-12-010, as listed below:

1. Department of General Services dated January 12, 1988

2. City of Long Beach dated January 13, 1988

3. Pacific Gas and Electric Company (all remaining issues) dated January 13, 1988

4. City of Palo Alto dated January 13, 1988

5. San Diego Gas & Electric Company dated January 26, 1988

6. Southern California Gas Company dated January 29, 1988

7. California Hotel and Motel Association dated February 4, 1988

8. Toward Utility Rate Normalization dated February 17, 1988

9. Southern California Utility Power Pool and Imperial Irrigation District dated March 9, 1988

In addition, numerous responses and counter responses to these petitions have been filed and fully considered.

A. Procurement Issues

1. TURN's Petition for Modification Dated Feb. 17, 1988

Toward Utility Rate Normalization (TURN) has asked that we modify D.87-12-039, D.86-12-009, and D.86-12-010 to change several of our procurement policies. Although TURN acknowledges that our ongoing procurement investigation would be an appropriate place to raise these issues, it feels that these issues need to be resolved at least on an interim basis before the May 1, 1988, implementation date, in order to avoid possible harmful impacts on core customers during the initial year of our new program.

TURN first suggests that core-elect procurement customers should pay the actual, rather than the forecasted, weighted average cost of gas (WACOG) for the core portfolio. TURN argues that the forecasts of the core WACOG are likely to be wrong, and that under or overcollections in the core gas cost balancing account will lead to incorrect signals to noncore customers to elect out of or into the core portfolio. For example, core-elect customers may elect out of the core portfolio in order to avoid having to pay for the amortization of a large undercollection which they may have helped to create. These customers might thus escape responsibility for the full costs of their procurement choice, leaving captive core customers to absorb additional costs. In the event of a large overcollection in the core gas account, noncore customers might have an undue incentive to elect into the core portfolio, to reap the advantages of an overcollection which they did not pay to create. TURN's solution to these problems is to charge core-elect customers the actual core WACOG each month, rather than a forecasted price. In effect, the core gas cost balancing account would not apply to core-elect customers, who would be charged a current price. If the Commission is concerned that such a change might reduce the rate certainty offered in the core portfolio, TURN suggests that the utilities be allowed to offer core-elect customers firm one-year contract prices, with the shareholders bearing the price risk for these contracts.

The California Manufacturers Association (CMA) and Pacific Gas and Electric Company (PG&E) filed responses opposing TURN's request. Both PG&E and CMA feel that TURN's proposal would decrease the attractiveness of core election. PG&E comments that TURN's proposal would reduce the price stability and predictability of the core portfolio. CMA cites D.86-12-010 as evidence that the Commission has already decided that the restrictions on core election should be minimized. CMA also argues that core-elect customers do not necessarily have accurate forecasts of future gas prices, and that TURN's concern about their ability to "game" core election is thus overblown. Finally, CMA notes that the Negotiated Revenue Stability Account (NRSA) stipulation which the Commission adopted in D.86-12-010 provides that the utilities shall file an offset case if the average total core rate deviates by four percent or more from the authorized (forecasted) rate.

We believe that TURN has raised an important problem, and has suggested a potential solution. However, we think that TURN may not have found the best solution, for reasons which the responses of CMA and PG&E have highlighted. We are interested in providing the utilities with the tools necessary to offer a core portfolio with stable and predictable prices; this is one of the key goals of our core procurement policy. Undeniably, this goal will be furthered by preventing large under or overcollections in the core gas balancing account, to prevent both sudden swings in the core WACOG and the sort of "gaming" of core election which TURN fears. Unfortunately, the stipulation which we adopted in D.86-12-010 actually may not prevent a large <u>gas cost</u> over or undercollection, because the filing trigger is based on the <u>total</u> core rate, which includes margin recovery as well as gas costs. For example, a large core margin overcollection could mask a core gas cost undercollection, as appears to have happened this winter in southern California. Thus, CMA's citation of the stipulation in opposition to TURN's petition is not really on point. We think that a better idea than TURN's proposal may be to develop a procedure which would allow the utilities to file to revise just the core WACOG, whenever the core gas balancing account threatens to become significantly out of balance, due solely to unexpected changes in gas costs or the sequence of purchases. Such a provision would address the concerns which we share with PG&E and CMA: that we not diminish the price stability of the core portfolio, that we not treat core-elect customers differently than other core users, and that we not make major revisions in our program at this late date. It would also encourage core gas suppliers to keep their prices stable enough to avoid the trigger for this gas cost offset procedure. We do not have enough information to set an appropriate trigger; we will ask the parties to the stipulation and to this case to try to work out an agreement for such a mechanism. We emphasize that such a procedure should be a simple mechanism to change the core WACOG to reflect new gas costs and purchasing sequence; the procedure should not involve extensive hearings or revisions to sales forecasts, cost allocation, or rate design. We view this procedure as simply a fine-tuning adjustment to our procurement policies, whose intent is to enhance the stability of the core portfolio. We will defer action on this issue until the parties have had the opportunity to work out such a procedure; in the meantime, we see no great immediate harm in allowing the program to begin with all core procurement customers paying the forecasted core WACOG.

TURN also proposed that the utilities be allowed to offer one-year, fixed price core procurement contracts, with the shareholders bearing the price risk. As this proposal does not seem to address any immediate problem, we will defer consideration of the idea to the gas procurement case, where we can examine it in the context of other options for revising our core procurement policies.

TURN is also concerned about the ability of core-elect customers to purchase only a portion of their annual requirements from the core portfolio. TURN notes that many noncore customers may elect into the core portfolio for only their winter requirements, and will purchase cheap spot gas during the summer. This would provide core-elect customers with the benefits of the core portfolio's supply security and price stability during the peak demands in the winter, and the price advantages of cheap spot gas during the low demand period in the summer. What worries TURN about this possibility is that the increased core demand during the high-cost winter period could increase the core WACOG, to the detriment of captive core customers. TURN's concern is based on the premise that the utilities would be unable to purchase additional long-term supplies to meet the increased winter-only core-elect demand, and would have to rely on increased purchases of high-cost winter spot gas. TURN asks us to impose some sort of restriction on core election that would prevent "winter-only" core election. One possibility, for example, would be to require customers who elect into the core for only a portion of their requirements to buy from the core an equal percentage of their total usage each month. TURN also notes that PG&E appears to have included language in its recently-filed core-elect tariff that would resolve this problem.[1]

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1 PG&E's proposed tariff language is as follows:

> "If you choose to purchase natural gas under Schedule G-PC (the core-elect tariff), as part of your Natural Gas Supply Agreement, you must elect to purchase either: 1) your full natural-

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The Division of Ratepayer Advocates (DRA) supports TURN's request, noting that what TURN proposes is essentially just an elaboration of the "portfolio switching ban" which the Commission adopted in D.86-12-010. This policy prevents noncore customers from electing into the core portfolio when the noncore portfolio is more expensive than the core portfolio. The switching ban is most likely to be in place in the winter, when demand peaks and spot prices are likely to rise. DRA points out that a customer could evade the ban by electing, sometime in the summer or fall, into the core for just his winter requirements.

CMA opposes this modification. CMA argues that restrictions such as this were considered by the Commission and

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> gas supply requirement from Schedule G-PC or 2) a specified portion of your full natural-gas supply requirement from Schedule G-PC. If you elect to purchase a portion of your full supply requirement from Schedule G-PC, you must specify, in therms, an Annual Contract Quantity (ACQ). The ACQ that you specify may not exceed your historical annual use of natural gas on your prior account(s) as determined by PG&E, unless otherwise agreed to by PG&E. You must also designate the portion of your ACQ which will be used in each calendar month. The ratio of your highest monthly contract quantity divided by your ACQ may not be greater than the ratio of your highest monthly use in the past 12 months divided by your total use in those 12 months."

This restriction would limit the core-elect customer's purchases from the core portfolio to a monthly profile whose seasonality is similar to his historical pattern. This proposal would allow for greater flexibility in core-elect takes than the restrictions suggested by TURN.

rejected in D.86-12-010. D.86-12-010 requires core-elect customers to specify only yearly contract amounts, and allows noncore customers to divide their total load among procurement options. CMA believes that, even with two gas portfolios and the possibility of self-procurement, there will be adequate diversity of demand in the core portfolio to avoid the problems TURN foresees.

Resolving this issue requires striking a careful balance: we do not want to place unnecessary restrictions on core election, yet we also want to protect captive core customers from increased costs due to unforeseen core election during the high-cost winter season. Because core-elect customers now are required to specify only annual contract amounts, the utilities have no way of knowing in what season this load will appear. TURN, DRA, and PG&E are justifiably concerned that unforeseen winter core-elect demand could require short-term purchases of high-cost gas. However, the restrictions they propose could reduce core election, and we have often observed that a healthy core-elect class may help the utility to reduce procurement costs for all core customers--a view that both PG&E and TURN have consistently supported.

Our solution at this time is to allow the utilities to impose the requirement in PG&E's tariff, at least until we have gained some actual experience under the new program. In D.86-12-010 we decided that core-elect customers must obligate themselves to purchase gas from the core portfolio for a period of at least one year. One year was the minimum obligation which we felt would give the utilities a reasonable ability to plan their purchases for the core portfolio. Customers who elect into the core portfolio intending to take core gas for only a portion of the year--just for the winter, for example--in our view are violating the spirit, if not the letter, of the one-year requirement. We also agree with DRA that "winter only" core election has the potential to result in the circumvention of the portfolio switching ban. We do not want to put the utilities into the position of having to buy high-priced winter spot gas in order to meet a sudden surge in customers who elect into the core in the fall, intending only to cover their winter requirements with core gas.' We recognize that on this issue a key uncertainty is the utility's ability to use storage to meet the swings in demand from core procurement customers. If the utilities have the storage capacity to meet core procurement demands which are highly seasonal, we might be able to relax the restriction we are imposing today. Ultimately, we hope that our experience under the new program will allow us to relax this restriction. However, because we have not completed our proceeding on storage issues, and because we have no actual operating experience under the new program, we find that the prudent approach is to adopt the restriction proposed by TURN, as embodied in PG&E's tariff language.

We will also require core-elect customers to provide the utility, at the time the core procurement contract is signed, with an estimate of monthly core-elect demand over the contract period. This information will help the utility to plan its core purchases and storage operations over the entire year in a way that minimizes core procurement costs. Customers will be required to supplement this information should their plans change. If so requested by the customer, the utility should keep this information confidential. We see no reason why the core-elect customer will not supply the utility with the customer's best estimate of monthly core-elect demand; it will be in the customer's best interest to provide the utility with an accurate forecast on which the utility can act to minimize its core procurement costs.

Therefore, we will modify D.86-12-010 to require core-elect customers to provide an updated forecast of their monthly core-elect demand over the contract period. In addition, D.86-12-010 should be modified to allow the utilities to add the PG&E tariff language cited by TURN to core procurement contracts.

The utilities should modify their tariff filings, if necessary, to reflect these modifications to the core procurement tariff.

TURN's final issue is a response to a provision in PG&E's newly filed tariff for sales to PG&E's electric department, which allows the electric department to "arrange for natural gas procurement from an outside source." TURN observes that allowing such separate procurement would make a mockery of our requirement that PG&E supply gas at either the core or noncore WACOGs, without targeting specific gas supplies to certain customers. It would also violate the "one company" policy which the Commission has long followed in reasonableness reviews of fuel purchases by combination utilities.

PG&E responds that its tariff language is based on D.86-12-010, which established that "UEG gas load should be treated as any other large noncore load" (Conclusion of Law 6). Thus, PG&E's electric department should have the full range of procurement options available to an electric-only utility. PG&E points out that the purpose of any gas procurement activities by the electric department will be to benefit electric customers, arguing that the electric department may be able to procure favorably priced gas without reducing the amount of similar supplies which are available to the core portfolio. PG&E states that it intends to comply with both the letter and the spirit of the Commission's "no targeting" policy, and reminds us that we have both gas and electric reasonableness reviews in which to enforce our directives.

The Independent Energy Producers Association (IEP) filed a response supporting TURN's request. IEP makes the additional arguments that PG&E's proposal has serious anticompetitive implications, and thus that the Commission cannot adopt it without considering these impacts, as required under Northern California Power Agency v. Public Utilities Commission (1971) 5 C 3d 370. IEP argues that if the electric department is able to procure cheap gas for PG&E's powerplants, the avoided cost rates paid to qualifying facilities (QFs) will also fall, potentially driving these competing electricity suppliers out of business. In addition, IEP paints a picture of PG&E's electric department siphoning off the cheapest gas supplies to the extent that other noncore customers will be forced into PG&E's core portfolio.

DRA supports PG&E on this issue. DRA also admits that the economics of cogeneration projects could be impacted negatively if the utility is consistently able to purchase gas at cheaper prices than what is available to cogenerators. However, DRA does not feel that the potential for such a scenario merits stronger action at this time than close monitoring.

This issue presents us with a situation in which two of our established policies, applied to a combined utility like PG&E, appear to be working at cross purposes. Granting PG&E's request might open up a backdoor circumvention of our current policy against the "targeting" of gas supplies. Yet foreclosing this possibility would deny PG&E's electric department the full range of procurement options which we have granted to electric-only utilities. We note that the equities of this issue essentially boil down to whether to favor gas or electric ratepayers; many of PG&E's ratepayers are both. We will deny TURN's request at this time, relying on PG&E's declared intention to honor our "no targeting" policy and on our ability to hold the utility to that commitment in reasonableness reviews. We concur with the DRA's view that the anticompetitive impact of this decision on QFs is speculative at best; we will monitor PG&E's UEG procurement activities closely to ensure that the utility's actions do not deny QFs the opportunity to procure competitively priced gas supplies. Finally, we note that this decision should be considered to be interim in nature, pending the completion of our integrated and comprehensive review of procurement policies in I.87-03-036.

2. SoCal's Petition for Modification Dated 1/29/88

Southern California Gas Company (SoCal) asks us to modify the spot market and El Paso gas prices which the implementation decision adopted for SoCal. SoCal argues that our adopted spot price of $1.75 per MMBtu did not account for possible sharp increases in spot prices during the 1987-88 winter months. Those increases have in fact occurred, and SoCal urges us now to adopt its original forecast of $1.90 per MMBtu. SoCal also points out that we adopted inconsistent El Paso prices for SoCal and PG&E, despite the fact that both companies buy gas from El Paso at the same price. SoCal would like us to use the higher El Paso price used in the PG&E cost of gas tables. The impact of these modifications is to raise the core cost of gas for SoCal by $23.9 million, and to increase the core WACOG from $2.109 per MMBtu to $2.161 per MMBtu. SoCal argues that this higher core WACOG will more accurately represent anticipated gas prices over the period until SoCal's first cost reallocation proceeding, and thus will minimize possible undercollections in the core gas cost balancing account. The DRA supports making the El Paso prices consistent, but feels that the decision's spot price forecast is still reasonable. CMA agrees with the DRA.

As TURN's response indicates, this issue is linked to the question of whether to charge core-elect customers the actual or the forecasted core WACOG. As we have discussed above, we are addressing means to limit the potential for customers to "game" core election in response to dramatic over or undercollections in the core gas cost balancing account. The steps we take on that issue will minimize what TURN has correctly pinpointed as the most serious problem that may arise from inaccurate forecasts of the core WACOG.

Considering this, and the views of CMA and DRA that the adopted spot price forecast is still appropriate, we will deny SoCal's request to modify the adopted spot price forecast. We agree with CMA and DRA that the decision's spot price forecast remains reasonable. We will, however, allow the modification which SoCal proposes to the El Paso price in order to achieve consistency with the adopted cost of gas for PG&E. This inconsistency in D.87-12-039 was a simple oversight. SoCal should revise its core portfolio WACOG to reflect the $2.22 per MMBtu El Paso price.

B. <u>Core/Noncore Definition</u>

1. <u>PG&E's Petition for Modification Dated 1/13/88</u>

PG&E requests a modification which would clarify our adopted definition of the core and noncore classes. PG&E asks us to clarify our adopted distinction between core and noncore customers with respect to two separate situations. The first involves customers who have economically and technically feasible alternative fuel facilities in place, but are otherwise too small to be considered noncore. The second involves users who are large enough to be considered noncore, who do not presently have alternative fuel equipment onsite, yet who have the capability to install technically and economically feasible alternative fuel facilities. PG&E notes, and all other parties who commented on this issue appear to agree, that D.87-12-039 seems to confuse these two situations. We agree that the decision is indeed confusing, and needs clarification.

However, there is some difference of opinion on exactly how to clarify this issue. DRA and SoCal presented detailed analyses of this issue, and raised a number of important points which the clarifying language suggested by PG&E does not specifically address. Although our intent in D.87-12-039 was to adopt the PG&E position on this issue, and the clarifying language PG&E has proposed would accomplish that, we think that SoCal and DRA have raised issues which need to be resolved.

SoCal agrees with PG&E's position that small (under 20,800 therms per month) core customers who already have standby equipment installed (i.e., small P2B customers), and who demonstrate that they cannot be served gas competitively at core rates, may qualify for noncore status. However, SoCal believes that small core customers who do not have alternative facilities presently installed should not be allowed to qualify for noncore status either by installing standby equipment or by passing a feasibility test for such an installation. Otherwise, SoCal fears the potential administrative chaos of a large number of small core customers seeking noncore service. SoCal also believes that large (20,800 therms per month or greater) P2A customers should not be granted noncore status without installing standby equipment; SoCal claims that for most such customers alternative fuel facilities are infeasible, or they would already have been installed. Finally, SoCal cautions that if we adopt any sort of feasibility test for determining core/noncore status, customers should be required to requalify yearly, and to accept the lower priority of noncore service.

DRA concurs with SoCal that only small core customers with existing alternate fuel facilities should be allowed to qualify for noncore status upon a showing of economic feasibility. DRA also urges us not to weaken the existing standby requirements for large P2B and P3 customers, without some experience under the new program and a better record on this issue. DRA points out the experience in the recent SoCal Gas curtailment, when a significant number of low priority customers were found not to have the requisite standby equipment in place. DRA reminds us that a cornerstone of our program is the requirement that noncore customers have a competitive option to utility gas service.

The California Hotel and Motel Association (CH&MA) and the Coalition of Declining Enrollment Schools (CODES) both object to any limitation which allows only small core customers with existing standby facilities to seek noncore status. These parties argue that such a restriction would deny to small core customers the opportunity to seek competitive options to utility service, and might result in a situation, for example, in which users who might be served gas at noncore rates would leave the system because core rates were above the costs of installing and using propane. CMA supports the exceptions which PG&E would allow to the alternate fuel requirements for large customers.

After reviewing these comments, as well as the record leading to D.87-12-039, we continue to support PG&E's basic position on the issues surrounding the core/noncore definition. We will clarify D.87-12-039 to require small core customers (less than 20,800 therms per month) to meet PG&E's three-pronged test in order to qualify for noncore status: (1) actual alternate fuel facilities are installed and capable of use on a sustained basis; (2) the cost of using alternate fuel would be lower than the price of core gas service; and (3) the customer is willing to accept the lower service priority of noncore service. This test satisfies SoCal's concern that such customers must have installed standby facilities. We will not adopt the SoCal/DRA proposal to limit the applicability of this test to small core customers with existing alternate fuel facilities; we agree with CH&MA and CODES that the impact of such a restriction might be to drive customers completely off the gas system. We will adopt SoCal's suggestion that users who qualify for noncore service in this way must requalify on an annual basis.

Considerable confusion swirls around the issue of the standby requirement for large customers (usage greater than 20,800 therms per month). For example, PG&E's Rule 21 refers to the technological feasibility of alternative fuel use, yet its G-50 and G-58 tariffs require installed facilities. Also, we note that a SoCal witness stated that "...the standby requirement has outlived its usefulness." Yet in its response to PG&E's petition on this issue, SoCal recommends that large P2A customers be required to install standby equipment in order to qualify for noncore status. After due consideration, we will adopt the position which PG&E

stated in its brief in I.86-06-005 (pp. 27-28): the existing standby requirements will be retained, with exceptions possible in cases where the customer has the clear technological capability to install alternate fuel facilities, and where the cost to do so and then to use alternate fuel would be less than the cost of core service. These exceptions will require the specific approval of the Commission. This resolution is generally consistent with the DRA's desire to retain the current standby requirements, on which the end use priority system and the core/noncore definition are essentially based, yet also acknowledges that there are some clear cases in which exceptions should be made in order to prevent wasteful investment in standby facilities.

C. Wholesale Issues

1. Long Beach's Petition for Modification Dated 1/13/88
2. Palo Alto's Petition for Modification Dated 1/13/88
3. SDG&E's Petition for Modification Dated 1/26/88

The City of Palo Alto, City of Long Beach, and San Diego Gas & Electric Company (SDG&E) have each filed a petition for modification of D.87-12-039. The petitions of these wholesale customers overlap to a great extent. The issues presented are listed below:

1. Reallocation of lost and unaccounted for gas (LUAF).
2. Reallocation of the long term transportation revenue shortfall.
3. Exclusion of uncollectibles from the procurement rate.
4. Relationship of the wholesale volumetric transmission rate and the UEG volumetric transmission rate.
5. Balancing account mechanism regarding wholesale customers.

6. The nature of core transmission service for wholesale customers.

7. The one-year notice requirement for switching back to the core portfolio.

Our discussion of these issues follows.

a. **Reallocation of LUAF**

b. **Reallocation of Long-Term Transport Revenue Shortfall**

SDG&E requests that these two costs items be reallocated so that these costs are not born by wholesale customers. This request is supported in part by Palo Alto and Long Beach and opposed by TURN, DRA, and PG&E.

This request is simply a rehash of the positions that these wholesale customers have taken in the past. The wholesale customer's views on the allocation of these cost items were fully considered in past decisions and no new arguments have been presented which would warrant a change. Therefore the requests that these cost items be reallocated will be denied.

c. **Exclusion of Uncollectibles From the Wholesale Procurement Rate**

SDG&E points out that D.87-12-039 provided that uncollectible expenses associated with transmission would not be allocated to wholesale customers; however the decision was silent regarding the treatment of uncollectible expenses associated with procurement. SDG&E requests that the decision be clarified and suggests that uncollectibles associated with procurement not be allocated to wholesale customers. Both TURN and DRA support the SDG&E position while PG&E opposes it. The PG&E position is that uncollectibles are a routine cost of doing business caused by all customers.

We have previously recognized that wholesale customers are not responsible for the incurrence of uncollectible expenses on the primary utility's system. Although this recognition was explicitly considered regarding fixed cost expenses, the logic holds true for commodity costs as well. We will modify D.87-12-039 to state explicitly that uncollectible expenses associated with procurement should not be allocated to wholesale customers.

d. Relationship of the Wholesale and UEG Volumetric Transmission Rates

D.87-12-039 sets the volumetric portion of the default rate for wholesale transmission service at a level equal to the volumetric default rate for UEG customers. Long Beach requests that the decision be modified to specify that the wholesale volumetric default rate is equal to the the actual UEG rate whether such rate is a default rate or a negotiated rate.

DRA opposes this request on the grounds that the wholesale rate design gives the wholesale customers more than adequate flexibility to negotiate an appropriate wholesale rate design of its own. We agree. Long Beach has not shown a reason sufficient to warrant changing the decision in the manner requested.

e. Balancing Account Mechanism Regarding Wholesale Customers

Both Long Beach and Palo Alto request that the decision be clarified regarding the applicability of the core balancing accounts to wholesale customers. Our review indicates that D.86-12-010 (pp. 124-161) discussed in detail the balancing and tracking accounts which will be established under the new structure. DRA's response to these petitions appears to summarize correctly the accounting aspects of the program, as they apply to wholesale customers.

D.86-12-010 makes it clear that there are no longer wholesale balancing accounts. This means that there are no special accounts for the overlying utility to "balance" expenses or sales to wholesale customers as a separate class. Also, we think that it is clear that balancing accounts have been removed for noncore transmission and for procurement from the noncore portfolio. Equally clear is the fact that there will be balancing accounts for the core for both procurement and transmission, i.e., respectively, Core Procurement Purchased Gas Adjustment Account and the Core Customer Fixed Costs Adjustment Account.

Regarding the core-elect, including wholesale customers to the extent they choose that option, we have clarified our previous orders in this decision to provide that core-elect customers will be included in the Core Procurement Purchased Gas Adjustment Account. Wholesale customers are treated like any other noncore customer and, to the extent that they elect into the core portfolio for procurement, they will pay the forecasted core WACOG for gas just like other core-elect customers. Thus, there is no need for a procurement balancing account specifically for wholesale customers' purchases. Likewise, we have never intended that noncore transmission throughput (including wholesale core-elect throughput) would be included in the Core Customer Fixed Costs Adjustment Account.

f. <u>Wholesale Core Transmission Service</u>

Both Palo Alto and Long Beach request that the Commission clarify the nature of core transmission service provided to wholesale customers. Both customers propose that they be afforded a twelve-month load balancing provision. This provision would allow the wholesale customers to purchase independently and deliver to the utilities more than current requirements in one season, then take the excess gas in another season, so long as the deliveries and takes balanced at the end of a twelve-month period.

TURN filed a response indicating support provided the quantities subject to the twelve-month load balancing were limited in some fashion and further provided that the mechanism would only be effective until a decision is issued in the storage and procurement investigation (I.87-03-036). TURN would limit the mechanism by not allowing the the wholesale customer's takes to be out of balance by a volume greater than the percentage of the serving utility's storage capacity equivalent to the percentage of storage costs assessed to that wholesale customer in the adopted cost allocation. This in effect gives the wholesale customer usage of storage on the serving utility's system.

We will adopt the TURN proposal temporarily, until we have reached a decision in the storage and procurement proceeding mentioned earlier, with two important qualifications. First, this load balancing mechanism will apply only to the core loads of the wholesale customers. Thus, we will mandate on an interim basis that the core loads of wholesale customers on "default" rates can be out of balance for a period up to twelve months in length. The maximum amount by which volumes purchased to serve the wholesale customer's core market can be out-of-balance will be limited to a volume equal to the percentage of the serving utility's storage capacity equivalent to the percentage of total storage costs assessed to the core customers of that wholesale customer in the adopted cost allocation. The second qualification is the caveat that this ability to load balance may be constrained by the operational capabilities of the serving utility.

g. One-year Notice Requirement

In responding to the petitions of others, TURN has pointed out an inconsistency in our treatment of noncore and wholesale customers. D.87-12-039 provided that if wholesale customers designate less than their high priority load as core procurement, then they must provide at least a one-year notice to shift this high priority load back into the core portfolio. This shift is also governed by the "portfolio switching ban". Other noncore customers are governed only by the "portfolio switching ban". TURN suggests that there is no need for the one-year notice and, to be consistent, the requirement should be dropped. We will delete the the one-year advance notice requirement for wholesale customers to shift load into the core portfolio. Only the "portfolio switching ban" will continue to govern.

D.87-12-039 stated that Hadson suggested the two-year amortization for the offset balancing accounts. Long Beach indicates that the proposal was in fact made by Long Beach. We acknowledge this fact.

D. <u>Commercial Rate Design Issues</u>

1. <u>CH&MA's Petition for Modification Dated 2/4/88</u>

2. <u>PG&E's Petition for Modification Dated 1/13/88</u>

CH&MA objects to the winter/summer rate differential which we imposed on core commercial customers of all three utilities. CH&MA complains that only PG&E proposed such a differential. CH&MA also asks us to reconsider our rejection of SoCal's proposed incentive rate for gas air conditioning. PG&E and DRA oppose CH&MA's petition; TURN supports it.

The arguments CH&MA advances do nothing more than reargue the positions which it advocated in the proceedings leading to D.87-12-039. We considered and rejected those arguments in that order, and CH&MA has not convinced us to change our minds. We will deny CH&MA's petition for modification.

PG&E raises the issue of the intent of the core commercial rate structure adopted for PG&E's service territory in D.87-12-039. We adopted "PG&E's proposed rate structure" to address the so-called "rose grower problem"--the situation in which two commercial customers, roughly equal in size but only one of which has alternate fuel capability, will have widely different rates. PG&E is unsure to which structure the decision refers: the large/small customers rate differential which PG&E proposed in Exhibit 139, or the illustrative declining block structure which PG&E filed in response to the ALJ's September 9, 1987, ruling. There was no opposition to PG&E's request that we clarify that the proposal referenced in the decision is the one in Exhibit 139. We will grant PG&E's request.

E. Noncore Rate Design Issues

1. PG&E's Petition for Modification Dated 1/13/88

PG&E asks us to clarify that the existing end-use priority system should continue in place, pending the Commission's further consideration of how to implement the priority charge concept. This clarification was not opposed, is reasonable, and we will adopt it.

2. CMA's Petition for Modification Dated 2/25/88

The petition for modification filed by CMA on February 25, 1988, raised three issues:

1. Calculation of D-1 demand charges for P-2b and G-IND customers in PG&E Advice Letter No. 1453-G.
2. Making negotiated contracts public.
3. Calculation of customer charges.

a. Calculation of D-1 Demand Charges

It is our understanding that PG&E intends to modify its AL No. 1453-G to resolve the first issue concerning the arithmetical calculation of demand charges. PG&E apparently will use SoCal's method to calculate D-1 demand charges. SoCal's method has not been protested, to our knowledge. Therefore, action does not appear to be required on this issue.

b. Public Notice of Negotiated Contracts

D.87-03-044 ordered that contracts for noncore transmission service less than five years in length should be submitted to our Commission Advisory and Compliance Division (CACD), which would then make the contracts available as required. CMA is concerned that neither D.87-03-044 nor D.87-12-039 makes it clear exactly when the contracts must be filed with us. Also, CMA would like the utilities to make the contracts available for inspection at several different utility district offices.

We are not sure that a petition for modification of D.87-12-039 is the proper forum to make such a request. However, we do feel strongly that no useful purpose would be served by placing unnecessary constraints on the public availability of these contracts. Such constraints merely increase transaction costs for gas customers. Thus, in the interest of expediency we will clarify D.87-12-039 by adding an additional paragraph to require that the utilities will file with our CACD each negotiated contract for transmission service with a duration of less than five years; these filings shall be made within five days of the date of contract execution. [2] At this point the utilities should also make the contract available for public inspection at their general offices. Within ten days of execution, the contract should be made available at any of the utilities' district offices where requests have been received to review such contracts.

c. <u>Calculation of Customer Charges</u>

CMA notes the D.87-12-039 is ambiguous regarding the calculation of customer charges for noncore customers. Our prior decisions were clear that a prior twelve-month period would be used in the calculation of customer charges. However, CMA points out that the twelve-month period could be a "set" historical period or a moving twelve-month average. If a set period were used it appears that the customer charge would be established once each year and would not change during the year. On the other hand, with a twelve-month moving average, the customer charge could be more responsive to the customer's immediate prior consumption level.

CMA alleges that PG&E is using the twelve-month moving average whereas SoCal is using the "set" historical method. CMA supports the PG&E method and implicitly requests that whatever method is adopted be consistent for both utilities. TURN also

2 As ordered in D.86-12-009 (p. 41), the utilities must file for our review and approval transmission contracts with terms of five years or longer.

supports a consistent method for both utilities. No parties filed in opposition to these requests.

The calculation of the D-1 demand charge relies on a twelve-month moving average. The twelve-month moving average will also result in more responsive customer charges. We will provide that the customer charges for noncore customers be based on a twelve-month moving average.

3. <u>DGS's Petition for Modification Dated 1/12/88</u>

4. <u>SDG&E's Petition for Modification Dated 1/26/88</u>

The state Department of General Services (DGS) filed a petition for modification which raises two issues that were not also subjects of its petition for rehearing, which we dealt with in D.88-03-041.

DGS asks us to require the utilities to post their noncore WACOG prices for the following month 5 to 10 days in advance of the dates on which interstate transport nominations are due. DGA argues that such advance notice will give customers time to shop around for the best price. DGS also proposes a true-up mechanism for the noncore WACOG.

PG&E opposes the posting requirement, stating that due to the timing of spot gas bids, it cannot determine the next month's noncore WACOG until very late in the month. PG&E is not opposed to DGS's noncore WACOG true-up mechanism, so long as the amortization of true-up balances can be extended beyond the next month if market conditions require.

SoCal states that as a matter of policy, it posts its noncore WACOG as soon as it is available, and argues that a posting requirement will not necessarily make it available any sooner.

DGS has not persuaded us that there is a significant problem with the current system for posting monthly noncore WACOGs. We will deny this request.

Both SDG&E and DGS offer proposals for non-core WACOG true-up. The DGS's proposed noncore WACOG true-up mechanism appears to be consistent with what we discussed in more general terms on p. 107 of the decision. We see no reason to make the decision any more specific on this issue, on which there was no dispute.

The SDG&E proposal is unclear, but our discussion of the DGS proposal above should resolve any uncertainty regarding our intention.

Finally, DGS asks us to delay the date for implementing rates "until 30 days after the Commission has issued decisions on storage unbundling, priority charges and access to interstate storage (sic)." In the alternative, DGS suggests an initial exemption from the minimum one-year term and the switching ban for core election. DGS bases this request largely upon the recent schedule revisions in I.87-03-036, arguing that the issues in that investigation need to be decided before a complete package of services would be available to customers. The utilities and DRA oppose this request.

We will deny DGS's request for a delay in the implementation date. We agree fully with the utilities and DRA that the program adopted in D.87-12-039 is fully capable of operating pending a decision on the issues in I.87-03-036. We remind DGS that May 1, 1988, is in not a deadline for making long-lasting procurement choices. As SoCal notes, parties such as DGS who are worried about the impact of unresolved storage and procurement issues are free to negotiate a short-term transportation contract, and to procure gas themselves or from the noncore portfolio, to carry them until decisions are issued in I.87-03-036.

5. <u>SCUPP's Petition for Modification Dated 3/9/88</u>

The Southern California Utility Power Pool and Imperial Irrigation District (SCUPP) ask us to reject SoCal's attempt to impose a "new and excessive" transmission charge for UEG igniter fuel. This issue centers upon the following language in D.87-12-039:

> D. Igniter Fuel Status
>
> Only PG&E raised this as an issue. Its recommendation is that this type of fuel, currently classified as P2A, be classified as core for transportation. This usage fits our basic definition of core service--no alternate fuel capability--and will be classified as core service.

D.87-12-039, at 100. SoCal's February 1, 1988 Advice Letter No. 1767 proposes a separate 32.667 cents per therm igniter fuel volumetric transmission rate for UEG customers. SCUPP filed the instant petition because it believes that this charge, which is equal to the average core transmission rate, conflicts with our statements about the rates to be charged to UEG customers and about the volumes that are to be included in the UEG Tier I. SCUPP contends that in D.86-12-010 we decided to treat UEG load as noncore for transmission, with the full range of noncore procurement options. Additionally, in D.87-12-039 we essentially continued the two-tiered UEG rate design first approved in D.86-08-082; this rate design includes igniter fuel volumes in Tier I. The Tier I transmission rate is a noncore rate. SCUPP notes that the only testimony in the implementation proceeding concerning core treatment of igniter fuel was PG&E's testimony that it proposed to treat the igniter fuel for Southern California Edison's Coolwater complex as core transmission volumes. There was no examination of the igniter fuel volumes to which SoCal applies its rate, and no discussion of the fact that treating these volumes as core would mean that UEG customers would be bearing distribution system fixed costs. We have determined that UEG customers should not be allocated such costs, since they receive service at the transmission level. SCUPP concludes that the extreme uncertainty surrounding the imposition of a core transmission rate for igniter fuel, especially for SoCal's UEG customers, argues in favor of specifying that such a charge should not apply at this time to SoCal's UEG customers.

SoCal's response disagrees with SCUPP's argument that we intended all UEG load to be noncore for transmission. SoCal cites page 16 of D.86-12-010: "The P-1 and P-2A load of a multiple use customer will still be considered core, but will be eligible for transmission-only service and all utility procurement options." Igniter fuel has a P2A priority. SoCal feels that it has appropriately followed D.86-12-010 and D.87-12-039 in establishing a core rate for the transmission of P-2A igniter fuel. SoCal does admit that, unlike PG&E, it did not include igniter fuel volumes as core load in its cost allocation. Thus, the imposition of its igniter fuel charge would result in overrecovery of $7.7 million annually from UEG customers. SoCal proposes several means of dealing with this overrecovery, including crediting the excess revenues to either the UEG class or to the core, or redoing the cost allocation with core treatment of igniter fuel volumes.

SoCal has correctly interpreted our intent in both D.86-12-010 and D.87-12-039. Although the great majority of UEG usage is noncore, igniter fuel usage does meet our definition of core load for transmission: P2A priority with no feasible alternative fuel capability. Thus, UEG customers are "multiple use" customers as discussed in D.86-12-010, and the core portion of their usage should be charged a core transmission rate. However, SCUPP has highlighted how little attention this issue received in this case, especially with respect to SoCal's UEG rates. The exact mechanics of how igniter fuel volumes should be determined and treated in SoCal's rate design received no scrutiny at all. SCUPP's point is well taken that the allocation of core distribution system fixed costs to igniter fuel use may be inappropriate. Thus, allocating excess igniter fuel revenues back to the core may overcharge UEG customers. In addition, we have repeatedly resisted breaking new ground or revisiting old issues on cost allocation. Given this admittedly confused situation, we think that the best solution is to adopt SCUPP's request now, while giving SoCal's UEG customers notice at this time that we will treat igniter fuel use as core load for cost allocation and rate design purposes in SoCal's first cost reallocation proceeding. Until then, SoCal should eliminate its separate igniter fuel transmission charge. PG&E's tariff provisions on igniter fuel are reasonable, given that the issue was covered in PG&E's testimony.

O R D E R

IT IS ORDERED that the parties to the NRSA stipulation adopted in D.86-12-010, as well as any interested parties to I.86-06-005, shall meet and confer to attempt to develop a procedure which would allow the utilities to file to revise just the core portfolio WACOG, whenever the Core Procurement Purchased Gas Adjustment Account threatens to become significantly out of balance, due to unexpected changes in gas costs or in the sequence of purchases for the core portfolio. This procedure shall be as simple as possible, and shall be based on the discussion in this order.

IT IS FURTHER ORDERED that D.87-12-039 and D.86-12-010 are modified as follows:

1. The last paragraph in the discussion section on page 66 of D.86-12-010 is replaced with the following:

> At Industrial Users' request, we will clarify that noncore customers may choose elected core procurement for only a portion of their gas requirements, if they wish. CMA raised the issue of whether core-elect customers must specify monthly contract quantities. Since we have allowed core election for less than a customer's full requirements, there is the potential, unless we allow the utilities to impose some restrictions, for a user to take

> his core elect volumes during only a portion of the year--for example, in the winter, when supplies may be tight and spot prices high. Such a pattern of core election, if widespread, could raise costs to all core customers by increasing the seasonality of core procurement load. We are uncertain whether the utilities have adequate storage capacity to handle such increased load swings; they might have to buy expensive winter spot gas in order to meet a sudden surge in core-elect demand. Such "winter-only" core election also could allow noncore customers to evade the portfolio switching ban which we adopt elsewhere in this order. Until we gain some experience under the new program, and take a closer look at the role of storage in the context of the new industry structure, we find it prudent to allow the utilities to impose reasonable restrictions on the monthly contract quantities of core-elect customers who do not buy core gas for their full requirements. Essentially, the utilities may require core-elect customers to take gas from the core portfolio in a pattern that approximates their historical month-by-month load profile. We also think that core-elect customers should provide the utilities with the user's best estimate of core-elect demand over the contract period; this will assist the company in planning its core portfolio purchases. This information need not be part of the core-elect purchase contract, and the utility should keep it confidential if the customer so requests.

2. The following is added to the adopted rules on page 67 of D.86-12-010:

> The utilities shall impose reasonable restrictions on the monthly contract quantities of partial-requirements core-elect customers, in order to discourage "winter-only" core election. A core-elect customer shall provide the utility with its best estimate of monthly core-elect demand over the length of the contract.

3. Conclusion of Law 32 of D.86-12-010 is modified to read:

> No take-or-pay provision for elected core procurement contracts is warranted at this time; however, the utilities shall impose reasonable restrictions on the monthly contract quantities of partial requirements core-elect customers in order to discourage "winter-only" core election.

4. SoCal shall modify its core portfolio price, submitted in compliance with D.87-12-039, to reflect the use of an El Paso price of $2.22 per MMBtu. The cost of gas table on page 62 of D.87-12-039 shall be modified to reflect this change.

5. The last full paragraph on page 45 of D.87-12-039 is modified to read:

> We will adopt the PG&E proposal for the small core customer with alternate fuel capability, based primarily on our belief that the core/noncore distinction should be based on alternate fuel capability and not on the size of the customer. Thus, in order to qualify for noncore status, a small (less than 20,800 therms per month) core customer must demonstrate: (1) that actual alternate fuel facilities are installed and capable of use on a sustained basis; (2) that the cost of using alternate fuel would be lower than the price of core gas service; and (3) that the customer is willing to accept the lower service priority of noncore service. Concerning the standby requirement for large customers, we will adopt the position which PG&E stated in its brief: the existing standby requirements will be retained, with exceptions possible in cases where the customer has the clear technological capability to install alternate fuel facilities, and where the cost to do so and then to use alternate fuel would be less than the cost of core service. These exceptions will require the specific approval of the Commission.
>
> We will also adopt SoCal's suggestion that customers who are classified as noncore as a result of either of these tests must requalify on an annual basis.

6. Finding of Fact 17 of D.87-12-039 should be amended to read:

> Core customers are those customers that have no alternative fuel capability. Therefore P1 and P2A customers that, because of their usage, would not otherwise be considered noncore may be reclassified as noncore, if such customers meet the following conditions: (1) actual alternate fuel facilities are installed and capable of use on a sustained basis; (2) the cost of using alternate fuel would be lower than the price of core gas service; and (3) the customer is willing to accept the lower service priority of noncore service. Customers large enough to be considered noncore, but that do not have the alternative fuel equipment on-site, will also be considered noncore if the customer clearly has the technological capability to use alternative fuel and would be able to do so at a cost that is less than the cost of core service.

7. The following Conclusion of Law 2a is added to D.87-12-039:

> 2a. For customers large enough to be considered noncore, exceptions to the standby requirement should require Commission authorization on a case-by-case basis.

8. Section IV.A.6 of D.87-12-039 entitled "Allocation of Franchise Fees and Uncollectibles" is modified to read as follows:

> All parties appear to agree that Franchise Fees should be allocated on a percent-of-revenue basis and that uncollectibles (both fixed cost related and commodity cost related) should not be allocated to wholesale customers.
>
> We will explicitly adopt the allocation method of SoCal (which was supported by CMA) for the detail of this allocation issue. The SoCal method produces results which closely match the cost incurrence pattern of this cost item.

9. Section X.A of D.87-12-039 entitled "Wholesale Procurement Flexibility" is modified to read as follows:

Palo Alto proposed that the wholesale customers be allowed wide latitude in electing into core procurement and also in renominating or changing their nominations. Designating load election actually involves both transportation and procurement. Palo Alto agrees that if adjustments in its transportation nominations require additional facilities, then the wholesale customer could be required to give adequate advance notice. Also, Palo Alto agrees that its proposed latitude in nominating load into the core be restricted to P1, P2A and P2B priorities.

Since there is such a large amount of agreement on these issues, we favor a more hands-off approach. The parties have historically concluded successful negotiations on subjects with the same degree of complexity. As TURN reminded us in its comments, such shifts in procurement nominations will be subject to the portfolio switching policies adopted in D.86-12-009 and D.86-12-010. We will allow the parties to negotiate such things as adjustments, growth, and prorations. For transportation designation, we will adopt the rule proposed by Palo Alto. We will let the parties negotiate concerning the true length of time to construct required new facilities.

The wholesale customers require additional flexibility to meet the needs of their customers at the lowest possible rates. A liberal load balancing mechanism will provide such flexibility until we have reached a decision in the ongoing storage and procurement investigation. We mandate on an interim basis that the core loads of wholesale customers on "default" rates can be out of balance for a period up to twelve months in length. The maximum amount by which volumes purchased to serve the wholesale customer's core market can be out-of-balance is limited to a volume equal to the percentage of the serving utility's storage capacity equivalent to the percentage of total storage costs assessed to the core customers of that wholesale customer in the adopted cost allocation.

10. Finding of Fact 100 of D.87-12-039 is modified to read as follows:

> 100. Wholesale customers' choice of portfolios for gas procurement is governed by the portfolio switching ban in the same fashion as other noncore customers.

11. Section IV.B.1 of D.87-12-039, entitled "Balancing Account Amortization," is modified to read as follows:

> The amortization for "offset balancing accounts" was somewhat controversial in this proceeding in that there were at least three different periods proposed. PG&E, supported by TURN, suggests a twelve-month period based on the theory that all customers will have experienced one complete annual cycle of usage.
>
> SoCal proposes a nine-month period, with the caveat that it would make an advice letter filing lowering the rates once the balancing account is zeroed out. This is opposed by TURN, who favors a twelve-month period because it will result in a rate decrease.
>
> Finally, Long Beach suggests that we tie in the amortization period to the length of time (two years) that the NRSA protection will be in existence. We agree with and will adopt the Long Beach proposal. By accepting this proposal we can provide for an extended period of rate stability while at the same time allowing the utilities ample opportunity to recover the balances. Also, the two-year time period is short enough so that it is likely that the customers who created the undercollection will also pay it off.

12. The last sentence in the first paragraph in the section headed "Large/Small Customer Differentials" on page 85 of D.87-12-039 is amended to read:

> PG&E's proposal in Exhibit 139 to divide the core commercial rate design into two schedules consisting of a monthly customer charge and flat, seasonally differentiated rates mitigates the rate differentials and, as

modified in the upcoming discussion, is adopted.

13. After the first full paragraph on page 43 of D.87-12-039, the following should be added:

> Until we have determined the implementation details of the unbundled priority charge, the utilities should use the current end-use priority system (P1 through P5) for capacity priority.

14. Section X of D.87-12-039 is modified by adding subsection L. as follows:

> L. <u>Contract Disclosure</u>
>
> D.87-03-044 provided that noncore transmission contracts would be made available for public inspection. Such contracts were to be filed with our CACD which would make them available as requested.
>
> D.87-03-044 did not address the timing of the contract filings with the CACD. More precision in the rules governing public disclosure of contracts will assist the utilities in formulating consistent tariff rules and clarify our intentions.
>
> The contracts referred to above should be filed with our CACD within five days of execution. Also, each utility shall make the contracts available at its general offices within 5 days of execution and, upon request, at any of its district offices within 10 days of execution.

15. Section IV.C.1 of D.87-12-039 entitled "Customer Charges" is modified to read as follows:

> D.86-12-009 provided that the customer charge proposal of DRA would be the basis for establishing customer charges. SoCal, SDG&E, and DRA have correctly implemented the customer charge concept, which is to have the charge vary by average monthly usage over a moving twelve-month historical period. The number of bands and the size of the bands, as contained

in the latest DRA filings, will be adopted. The new PG&E proposal (unsupported by other parties) to have flat customer charges for all customers in a class will be rejected because it does not reflect costs and does not implement our prior orders.

16. The discussion under the heading "Igniter Fuel Status" on page 100 of D.87-12-039 is modified to read as follows:

Only PG&E raised this as an issue and incorporated its recommendation into its cost allocation and rate design. PG&E asked that this type of fuel, currently classified as P2A, be classified as a core load for transmission service. This usage fits our definition of core service--no alternate fuel capability. We will allow PG&E to classify and establish a rate for the transmission of igniter fuel as a core transmission service.

Neither SoCal nor its UEG customers raised the issue of the status of igniter fuel volumes. Under SoCal's current UEG rate design, whose structure is largely incorporated in the default UEG rate which we are adopting, igniter fuel volumes are included in Tier I volumes. Due to the lack of attention which this issue received in SoCal's rate design, we will allow igniter fuel to be treated as a noncore, Tier I load at this time. We put SoCal and its UEG customers on notice that in SoCal's first cost reallocation proceeding we intend to treat igniter fuel as a core load in SoCal's cost allocation and rate design as well as in PG&E's.

IT IS FURTHER ORDERED that, to the extent they are not granted or deferred above, all petitions for modification of D.87-12-039 are denied.

This order is effective today.

Dated March 23, 1988, at San Francisco, California.

STANLEY W. HULETT
President
DONALD VIAL
FREDERICK R. DUDA
G. MITCHELL WILK
JOHN B. OHANIAN
Commissioners

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

Victor Weisser, Executive Director

COM/DV/rtb/cgm/fs

Decision ______________________________

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's motion into implementing a rate design for unbundled gas utility services consistent with policies adopted in Decision 86-03-057.	I.86-06-005 (Filed June 5, 1986)
	R.86-06-006 (Filed June 5, 1986)
And Related Matters.	Application 87-01-033 (Filed January 20, 1987)
	Application 87-01-037 (Filed January 27, 1987)
	Application 87-04-040 (Filed April 20, 1987)

OPINION

D. 88-03-041, issued March 9, 1988, denied several petitions for modification of D. 87-12-039, the final implementation order in our effort to restructure, on an unbundled basis, the rates of California gas utilities. This order addresses the remaining petitions for modification of that order.

A. Procurement Issues

1. TURN's Petition for Modification dated Feb. 17, 1988.

Toward Utility Rate Normalization (TURN) has asked that we modify D. 87-12-039, D. 86-12-009, and D. 86-12-010 to change several of our procurement policies. Although TURN acknowledges that our ongoing procurement investigation would be an appropriate place to raise these issues, it feels that these issues need to be resolved at least on an interim basis before the May 1, 1988, implementation date, in order to avoid possible harmful impacts on core customers during the initial year of our new program.

TURN first suggests that core elect procurement customers should pay the actual, rather than the forecasted, weighted average cost of gas (WACOG) for the core portfolio. TURN argues that the forecasts of the core WACOG are likely to be wrong, and that under or overcollections in the core gas cost balancing account will lead to incorrect signals to noncore customers to elect out of or into the core portfolio. For example, core elect customers may elect out of the core portfolio in order to avoid having to pay for the amortization of a large undercollection which they may have helped to create. These customers might thus escape responsibility for the full costs of their procurement choice, leaving captive core customers to absorb additional costs. In the event of a large overcollection in the core gas account, noncore customers might have an undue incentive to elect into the core portfolio, to reap the advantages of an overcollection which they did not pay to create. TURN's solution to these problems is to charge core elect customers the actual core WACOG each month, rather than a forecasted price. In effect, the core gas cost balancing account would not apply to core elect customers, who would be charged a current price. If the Commission is concerned that such a change might reduce the rate certainty offered in the core portfolio, TURN suggests that the utilities be allowed to offer core elect customers firm one-year contract prices, with the shareholders bearing the price risk for these contracts.

The California Manufacturers Association (CMA) and Pacific Gas and Electric (PG&E) filed responses opposing TURN's request. Both PG&E and CMA feel that TURN's proposal would decrease the attractiveness of core election. PG&E comments that TURN's proposal would reduce the price stability and predictability of the core portfolio. CMA cites D. 86-12-010 as evidence that the

Commission has already decided that the restrictions on core election should be minimized. CMA also argues that core elect customers do not necessarily have accurate forecasts of future gas prices, and that TURN's concern about their ability to "game" core election is thus overblown. Finally, CMA notes that the Negotiated Revenue Stability Account (NRSA) stipulation which the Commission adopted in D. 86-12-010 provides that the utilities shall file an offset case if the average total core rate deviates by four percent or more from the authorized (forecasted) rate.

We believe that TURN has raised an important problem, and has suggested a potential solution. However, we think that TURN may not have found the best solution, for reasons which the responses of CMA and PG&E have highlighted. We are interested in providing the utilities with the tools necessary to offer a core portfolio with stable and predictable prices; this is one of the key goals of our core procurement policy. Undeniably, this goal will be furthered by preventing large under or overcollections in the core gas balancing account, to prevent both sudden swings in the core WACOG and the sort of "gaming" of core election which TURN fears. Unfortunately, the stipulation which we adopted in D. 86-12-010 actually may not prevent a large gas cost over or undercollection, because the filing trigger is based on the total core rate, which includes margin recovery as well as gas costs. For example, a large core margin overcollection could mask a core gas cost undercollection, as appears to have happened this winter in southern California. Thus, CMA's citation of the stipulation in opposition to TURN's petition is not really on point. We think that a better idea than TURN's proposal may be to develop a procedure which would allow the utilities to file to revise just the core WACOG, whenever the core gas balancing account threatens to become significantly out of balance, due solely to unexpected changes in gas costs or the sequence of purchases. Such a provision would address the concerns which we share with PG&E and CMA: that we not diminish the price stability of the core portfolio, that we not treat core elect customers differently than other core users, and that we not make major revisions in our program at this late date. It would also encourage core gas suppliers to keep their prices stable enough to avoid the trigger for this gas cost offset procedure. We do not have enough information to set an appropriate trigger; we will ask the parties to the stipulation and to this case to try to work out an agreement for such a mechanism. We emphasize that such a procedure should be a simple mechanism to change the core WACOG to reflect new gas costs and purchasing sequence; the procedure should not involve extensive hearings or revisions to sales forecasts, cost allocation, or rate design. We view this procedure as simply a fine-tuning adjustment to our procurement policies, whose intent is to enhance the stability of the core portfolio. We will not act on this issue until the parties have had the opportunity to work out such a procedure; in the meantime, we see no great immediate harm in allowing the program to begin with all core procurement customers paying the forecasted core WACOG.

TURN also proposed that the utilities be allowed to offer one-year, fixed price core procurement contracts, with the shareholders bearing the price risk. As this proposal does not seem to address any immediate problem, we will defer consideration of the idea to the gas procurement case, where we can examine it in the context of other options for revising our core procurement policies.

TURN is also concerned about the ability of core elect customers to purchase only a portion of their annual requirements from the core portfolio. TURN notes that many noncore customers may elect into the core portfolio for only their winter requirements, and will purchase cheap spot gas during the summer. This would provide core elect customers with the benefits of the core portfolio's supply security and price stability during the peak demands in the winter, and the price advantages of cheap spot gas during the low demand period in the summer. What worries TURN about this possibility is that the increased core demand during the high-cost winter period could increase the core WACOG, to the detriment of captive core customers. TURN's concern is based on the premise that the utilities would be unable to purchase additional long-term supplies to meet the increased winter-only core elect demand, and would have to rely on increased purchases of high-cost winter spot gas. TURN asks us to impose some sort of restriction on core election that would prevent "winter-only" core election. One possibility, for example, would be to require customers who elect into the core for only a portion of their requirements to buy from the core an equal percentage of their total usage each month. TURN also notes that PG&E appears to have included language in its recently-filed core elect tariff that would resolve this problem.

The Division of Ratepayer Advocates (DRA) supports TURN's request, noting that what TURN proposes is essentially just an elaboration of the "portfolio switching ban" which the Commission adopted in D. 86-12-010. This policy prevents noncore customers from electing into the core portfolio when the noncore portfolio is more expensive than the core portfolio. The switching ban is most likely to be in place in the winter, when demand peaks and spot prices are likely to rise. DRA points out that a customer could evade the ban by electing, sometime in the summer or fall, into the core for just his winter requirements.

CMA opposes this modification. CMA argues that restrictions such as this were considered by the Commission and rejected in D. 86-12-010. D. 86-12-010 requires core elect customers to specify only yearly contract amounts, and allows noncore customers to divide their total load among procurement options. CMA believes that, even with two gas portfolios and the possibility of self-procurement, there will be adequate diversity of demand in the core portfolio to avoid the problems TURN forsees.

Resolving this issue requires striking a careful balance: we do not want to place unnecessary restrictions on core election, yet we also want to protect captive core customers from increased costs due to unforeseen core election during the high-cost winter season. Because core elect customers now are required to specify only annual contract amounts, the utilities have no way of knowing in what season this load will appear. TURN, DRA, and PG&E are justifiably concerned that unforeseen winter core elect demand could require short-term purchases of high-cost gas. However, the restrictions they propose could reduce core election, and we have often observed that a healthy core elect class may help the utility to reduce procurement costs for all core customers -- a view that both PG&E and TURN have consistently supported.

Our solution at this time is to allow the utilities to impose the requirement in PG&E's tariff, at least until we have gained some actual experience under the new program. In D. 86-12-010 we decided that core elect customers must obligate themselves to purchase gas from the core portfolio for a period of at least one year. One year was the minimum obligation which we felt would give the utilities a reasonable ability to plan their purchases for the core portfolio. Customers who elect into the core portfolio intending to take core gas for only a portion of the year -- just for the winter, for example -- in our view are violating the spirit, if not the letter, of the one year requirement. We also agree with DRA that "winter only" core election has the potential to result in the circumvention of the portfolio switching ban. We do not want to put the utilities into the position of having to buy high-priced winter spot gas in order to meet a sudden surge in customers who elect into the core in the fall, intending only to cover their winter requirements with core gas. We recognize that on this issue a key uncertainty is the utility's ability to use storage to meet the swings in demand from core procurement customers. If the utilities have the storage capacity to meet core procurement demands which are highly seasonal, we might be able to relax the restriction we are imposing today. Ultimately, we hope that our experience under the new program will allow us to relax this restriction. However, because we have not completed our proceeding on storage issues, and because we have no actual operating experience under the new program, we find that the prudent approach is to adopt the restriction proposed by TURN, as embodied in PG&E's tariff language.

We will also require core elect customers to provide the utility, at the time the core procurement contract is signed, with an estimate of monthly core elect demand over the contract period. This information will help the utility to plan its core purchases and storage operations over the entire year in a way that minimizes core procurement costs. Customers will be required to supplement this information should their plans change. If so requested by the customer, the utility should keep this information confidential. We see no reason why the core elect customer will not supply the utility with the customer's best estimate of monthly core elect demand; it will be in the customer's best interest to provide the utility with an accurate forecast on which the utility can act to minimize its core procurement costs.

Therefore, we will modify D. 86-12-010 to require core elect customers to provide an updated forecast of their monthly core elect demand over the contract period. In addition, D. 86-12-010 should be modified to allow the utilities to add the PG&E tariff language cited by TURN to core procurement contracts. The utilities should modify their tariff filings, if necessary, to reflect these modifications to the core procurement tariff.

TURN's final issue is a response to a provision in PG&E's newly-filed tariff for sales to PG&E's electric department, which allows the electric department to "arrange for natural gas procurement from an outside source." TURN observes that allowing such separate procurement would make a mockery of our requirement that PG&E supply gas at either the core or noncore WACOGs, without targeting specific gas supplies to certain customers. It would also violate the "one company" policy which the Commission has long followed in reasonableness reviews of fuel purchases by combination utilities.

PG&E responds that its tariff language is based on D. 86-12-010, which established that "UEG gas load should be treated as any other large noncore load" (Conclusion of Law No. 6). Thus, PG&E's electric department should have the full range of procurement options available to an electric-only utility. PG&E points out that the purpose of any gas procurement activities by the electric department will be to benefit electric customers, arguing that the electric department may be able to procure favorably-priced gas without reducing the amount of similar supplies which are available to the core portfolio. PG&E states that it intends to comply with both the letter and the spirit of the Commission's "no targeting" policy, and reminds us that we have both gas and electric reasonableness reviews in which to enforce our directives.

The Independent Energy Producers Association (IEP) filed a response supporting TURN's request. IEP makes the additional arguments that PG&E's proposal has serious anticompetitive implications, and thus that the Commission cannot adopt it without considering these impacts, as required under Northern California Power Agency v. Public Utilities Commission 5 C3d 370 (1971). IEP argues that if the electric department is able to procure cheap gas for PG&E's powerplants, the avoided cost rates paid to qualifying facilities (QFs) will also fall, potentially driving these competing electricity suppliers out of business. In addition, IEP paints a picture of PG&E's electric department siphoning off the cheapest gas supplies to the extent that other noncore customers will be forced into PG&E's core portfolio.

DRA supports PG&E on this issue. DRA also admits that the economics of cogeneration projects could be impacted negatively if the utility is consistently able to purchase gas at cheaper prices than what is available to cogenerators. However, DRA does not feel that the potential for such a scenario merits stronger action at this time than close monitoring.

This issue presents us with a situation in which two of our established policies, applied to a combined utility like PG&E, appear to be working at cross purposes. Granting PG&E's request might open up a backdoor circumvention of our current policy against the "targeting" of gas supplies. Yet foreclosing this possibility would deny PG&E's electric department the full range of procurement options which we have granted to electric-only utilities. We note that the equities of this issue essentially boil down to whether to favor gas or electric ratepayers; many of PG&E's ratepayers are both. We will deny TURN's request at this time, relying on PG&E's declared intention to honor our "no targeting" policy and on our ability to hold the utility to that commitment in reasonableness reviews. We concur with the DRA's view that the anticompetitive impact of this decision on QFs is speculative at best; we will monitor PG&E's UEG procurement activities closely to ensure that the utility's actions do not deny QFs the opportunity to procure competitively-priced gas supplies. Finally, we note that this decision should be considered to be interim in nature, pending the completion of our integrated and comprehensive review of procurement policies in I. 87-03-036.

2. SoCal Gas' Petition for Modification dated 1/29/88.

Southern California Gas (SoCal) asks us to modify the spot market and El Paso gas prices which the implementation decision adopted for SoCal. SoCal argues that our adopted spot price of $1.75 per MMBtu did not account for possible sharp increases in spot prices during the 1987-88 winter months. Those increases have in fact occurred, and SoCal urges us now to adopt its original forecast of $1.90 per MMBtu. SoCal also points out that we adopted inconsistent El Paso prices for SoCal and PG&E, despite the fact that both companies buy gas from El Paso at the same price. SoCal would like us to use the higher El Paso price used in the PG&E cost of gas tables. The impact of these modifications is to raise the core cost of gas for SoCal by $23.9 million, and to increase the core WACOG from $2.109 per MMBtu to $2.161 per MMBtu. SoCal argues that this higher core WACOG will more accurately represent anticipated gas prices over the period until SoCal's first cost reallocation proceeding, and thus will minimize possible undercollections in the core gas cost balancing account. The DRA supports making the El Paso prices consistent, but feels that the decision's spot price forecast is still reasonable. CMA agrees with the DRA.

As TURN's response indicates, this issue is linked to the question of whether to charge core elect customers the actual or the forecasted core WACOG. As we have discussed above, we are addressing means to limit the potential for customers to "game" core election in response to dramatic over or undercollections in the core gas cost balancing account. The steps we take on that issue will minimize what TURN has correctly pinpointed as the most serious problem that may arise from inaccurate forecasts of the core WACOG.

Considering this, and the views of CMA and DRA that the adopted spot price forecast is still appropriate, we will deny SoCal's request to modify the adopted spot price forecast. We agree with CMA and DRA that the decision's spot price forecast remains reasonable. We will, however, allow the modification which SoCal proposes to the El Paso price in order to achieve consistency with the adopted cost of gas for PG&E. This inconsistency in D. 87-12-039 was a simple oversight. SoCal should revise its core portfolio WACOG to reflect the $2.22 per MMBtu El Paso price.

B. Core/Noncore Definition

1. PG&E's Petition for Modification dated 1/13/88.

PG&E requests a modification which would clarify our adopted definition of the core and noncore classes. PG&E asks us to clarify our adopted distinction between core and noncore customers with respect to two separate situations. The first involves customers who have economically and technically feasible alternative fuel facilities in place, but are otherwise too small to be considered noncore. The second involves users who are large enough to be considered noncore, who do not presently have alternative fuel equipment onsite, yet who have the capability to install technically and economically feasible alternative fuel facilities. PG&E notes, and all other parties who commented on this issue appear to agree, that D. 87-12-039 seems to confuse these two situation. We agree that the decision is indeed confusing, and needs clarification.

However, there is some difference of opinion on exactly how to clarify this issue. DRA and SoCal presented detailed analyses of this issue, and raised a number of important points which the clarifying language suggested by PG&E does not specifically address. Although our intent in D. 87-12-039 was to adopt the PG&E position on this issue, and the clarifying language PG&E has proposed would accomplish that, we think that SoCal and DRA have raised issues which need to be resolved.

SoCal agrees with PG&E's position that small (under 20,800 therms per month) core customers who already have standby equipment installed (i.e., small P2B customers), and who demonstrate that they cannot be served gas competitively at core rates, may qualify for noncore status. However, SoCal believes that small core customers who do not have alternative facilities presently installed should not be allowed to qualify for noncore status either by installing standby equipment or by passing a feasibility test for such an installation. Otherwise, SoCal fears the potential administrative chaos of a large number of small core customers seeking noncore service. SoCal also believes that large (20,800 therms per month or greater) P2A customers should not be granted noncore status without installing standby equipment; SoCal claims that for most such customers alternative fuel facilities are infeasible, or they would already have been installed. Finally, SoCal cautions that if we adopt any sort of feasibility test for determining core/noncore status, customers should be required to requalify yearly, and to accept the lower priority of noncore service.

DRA concurs with SoCal that only small core customers with existing alternate fuel facilities should be allowed to qualify for noncore status upon a showing of economic feasibility. DRA also urges us not to weaken the existing standby requirements for large P2B and P3 customers, without some experience under the new program and a better record on this issue. DRA points out the experience in the recent SoCal Gas curtailment, when a significant number of low priority customers were found not to have the requisite standby equipment in place. DRA reminds us that a cornerstone of our program is the requirement that noncore customers have a competitive option to utility gas service.

The California Hotel and Motel Association (CH&MA) and the Coalition of Declining Enrollment Schools (CODES) both object to any limitation which allows only small core customers with existing standby facilities to seek noncore status. These parties argue that such a restriction would deny to small core customers the opportunity to seek competitive options to utility service, and might result in a situation, for example, in which users who might be served gas at noncore rates would leave the system because core rates were above the costs of installing and using propane. CMA supports the exceptions which PG&E would allow to the alternate fuel requirements for large customers.

After reviewing these comments, as well as the record leading to D. 87-12-039, we continue to support PG&E's basic position on the issues surrounding the core/noncore definition. We will clarify D. 87-12-039 to require small core customers (less than 20,800 therms per month) to meet PG&E's three-pronged test in order to qualify for noncore status: 1) actual alternate fuel facilities are installed and capable of use on a sustained basis; 2) the cost of using alternate fuel would be lower than the price of core gas service; and 3) the customer is willing to accept the lower service priority of noncore service. This test satisfies SoCal's concern that such customers must have installed standby facilities. We will not adopt the SoCal/DRA proposal to limit the applicability of this test to small core customers with existing alternate fuel facilities; we agree with CH&MA and CODES that the impact of such a restriction might be to drive customers completely off the gas system. We will adopt SoCal's suggestion that users who qualify for noncore service in this way must requalify on an annual basis.

Considerable confusion swirls around the issue of the standby requirement for large customers (usage greater than 20,800 therms per month). For example, PG&E's Rule 21 refers to the technological feasibility of alternative fuel use, yet its G-50 and G-58 tariffs require installed facilities. Also, we note that a SoCal witness stated that "...the standby requirement has outlived its usefulness." Yet in its response to PG&E's petition on this issue, SoCal recommends that large P2A customers be required to install standby equipment in order to qualify for noncore status. After due consideration, we will adopt the position which PG&E stated in its brief in I. 86-06-005 (pp. 27-28): the existing standby requirements will be retained, with exceptions possible in cases where the customer has the clear technological capability to install alternate fuel facilities, and where the cost to do so and then to use alternate fuel would be less than the cost of core service. These exceptions will require the specific approval of the Commission. This resolution is generally consistent with the DRA's desire to retain the current standby requirements, on which the end use priority system and the core/noncore definition are essentially based, yet also acknowledges that there are some clear cases in which exceptions should be made in order to prevent wasteful investment in standby facilities.

C. Wholesale Issues

1. Long Beach's Petition for Modification dated 1/13/88.
2. Palo Alto's Petition for Modification dated 1/13/88.
3. SDG&E's Petition for Modification dated 1/26/88.

The City of Palo Alto, City of Long Beach, and San Diego Gas and Electric (SDG&E) have each filed a petition for modification of D.87-12-039. The petitions of these wholesale customers overlap to a great extent. The issues presented are listed below:

1. Reallocation of lost and unaccounted for gas (LUAF).
2. Reallocation of the long term transportation revenue short-fall.
3. Exclusion of uncollectibles from the procurement rate.
4. Relationship of the wholesale volumetric transmission rate and the UEG volumetric transmission rate.
5. Balancing account mechanism regarding wholesale customers.
6. The nature of core transmission service for wholesale customers.
7. The one-year notice requirement for switching back to the core portfolio.

Our discussion of these issues follows.

a) Reallocation of LUAF.

b) Reallocation of long term transport revenue shortfall.

SDG&E requests that these two costs items be reallocated so that these costs are not born by wholesale customers. This request is supported in part by Palo Alto and Long Beach and opposed by TURN, DRA, and PG&E.

This request is simply a rehash of the positions that these wholesale customers have taken in the past. The wholesale customer's views on the allocation of these cost items were fully considered in past decisions and no new arguements have been presented which would warrant a change. Therefore the requests that these cost items be reallocated will be denied.

c) Exclusion of uncollectibles from the wholesale procurement rate.

SDG&E points out that D.87-12-039 provided that uncollectible expenses associated with transmission would not be allocated to wholesale customers; however the decision was silent regarding the treatment of uncollectible expenses associated with procurement. SDG&E requests that the decision be clarified and suggests that uncollectibles associated with procurement not be allocated to wholesale customers. Both TURN and DRA support the SDG&E position while PG&E opposes it. The PG&E position is that uncollectibles are a routine cost of doing business caused by all customers.

We have previously recognized that wholesale customers are not responsible for the incurrence of uncollectible expenses on the primary utility's system. Although this recognition was explicitly considered regarding fixed cost expenses, the logic holds true for commodity costs as well. We will modify D.87-12-039 to state explicitly that uncollectible expenses associated with procurement should not be allocated to wholesale customers.

d) **Relationship of the wholesale and UEG volumetric transmission rates.**

D.87-12-039 sets the volumetric portion of the default rate for wholesale transmission service at a level equal to the volumetric default rate for UEG customers. Long Beach requests that the decision be modified to specify that the wholesale volumetric default rate is equal to the the actual UEG rate whether such rate is a default rate or a negotiated rate.

DRA opposes this request on the grounds that the wholesale rate design gives the wholesale customers more than adequate flexibility to negotiate an appropriate wholesale rate design of its own. We agree. Long Beach has not shown a reason sufficient to warrant changing the decison in the manner requested.

e) **Balancing account mechanism regarding wholesale customers.**

Both Long Beach and Palo Alto request that the decison be clarified regarding the applicability of the core balancing accounts to wholesale customers. Our review indicates that D. 86-12-010 (pp. 124-161) discussed in detail the balancing and tracking accounts which will be established under the new structure. DRA's response to these petitions appears to summarize correctly the accounting aspects of the program, as they apply to wholesale customers.

D.86-12-010 makes it clear that there are no longer wholesale balancing accounts. This means that there are no special accounts for the overlying utility to "balance" expenses or sales to wholesale customers as a separate class. Also, we think that it is clear that balancing accounts have been removed for noncore transmission and for procurement from the noncore portfolio. Equally clear is the fact that there will be balancing accounts for the core for both procurement and transmission, i.e., respectively, Core Procurement Purchased Gas Adjustment Account and the Core Customer Fixed Costs Adjustment Account.

Regarding the core-elect, including wholesale customers to the extent they choose that option, we have clarified our previous orders in this decision to provide that, at least for the time being, core-elect customers will be included in the Core Procurement Purchased Gas Adjustment Account. Wholesale customers are treated like any other noncore customer and, to the extent that they elect into the core portfolio for procurement, they will pay the forecasted core WACOG for gas just like other core elect customers. Thus, there is no need for a procurement balancing account specifically for wholesale customers' purchases. Likewise, we have never intended that noncore transmission throughput (including wholesale core-elect throughput) would be included in the Core Customer Fixed Costs Adjustment Account.

f) Wholesale Core Transmission Service.

Both Palo Alto and Long Beach request that the Commission clarify the nature of core transmission service provided to wholesale customers. Both customers propose that they be afforded a twelve month load balancing provision. This provision would allow the wholesale customers to purchase independently and deliver to the utilities more than current requirements in one season, then take the excess gas in another season, so long as the deliveries and takes balanced at the end of a twelve month period.

TURN filed a response indicating support provided the quantities subject to the twelve month load balancing were limited in some fashion and further provided that the mechanism would only be effective until a decision is issued in the storage and procurement investigation (I.87-03-036). TURN would limit the mechanism by not allowing the the wholesale customer's takes to be out of balance by a volume greater than the percentage of the serving utility's storage capacity equivalent to the percentage of storage costs assessed to that wholesale customer in the adopted cost allocation. This in effect gives the wholesale customer usage of storage on the serving utility's system.

We will adopt the TURN proposal temporarily, until we have reached a decision in the storage and procurement proceeding mentioned earlier. This load balancing mechanism together with the seasonal core-election procedure adopted earlier in this decision should provide wholesale customers with more than enough flexibility and security to fulfill the needs of their customers.

g) One-year Notice Requirement.

In responding to the petitions of others, TURN has pointed out an inconsistency in our treatment of noncore and wholesale customers. D.87-12-039 provided that if wholesale customers designate less than their high priority load as core procurement, then they must provide at least a one-year notice to shift this high priority load back into the core portfolio. This shift is also governed by the "portfolio switching ban". Other noncore customers are governed only by the "portfolio switching ban". TURN suggests that there is no need for the one-year notice and, to be consistent, the requirement should be dropped. We will delete the the one-year advance notice requirement for wholesale customers to shift load into the core portfolio. Only the "portfolio switching ban" will continue to govern.

D.87-12-039 stated that Hadson suggested the two year amortization for the offset balancing accounts. Long Beach indicates that the proposal was in fact made by Long Beach. We acknowledge this fact.

D. Commercial Rate Design Issues

1. CH/MA's Petition for Modification dated 2/4/88.
2. PG&E's Petition for Modification dated 1/13/88.

CH&MA objects to the winter/summer rate differential which we imposed on core commercial customers of all three utilities. CH&MA complains that only PG&E proposed such a differential. CH&MA also asks us to reconsider our rejection of SoCal's proposed incentive rate for gas air conditioning. PG&E and DRA oppose CH&MA's petition; TURN supports it.

The arguments CH&MA advances do nothing more than reargue the positions which it advocated in the proceedings leading to D. 87-12-039. We considered and rejected those arguments in that order, and CH&MA has not convinced us to change our mind. We will deny CH&MA's petition for modification.

PG&E raises the issue of the intent of the core commercial rate structure adopted for PG&E's service territory in D. 87-12-039. We adopted "PG&E's proposed rate structure" to address the so-called "rose grower problem" -- the situation in which two commercial customers, roughly equal in size but only one of which has alternate fuel capability, will have widely different rates. PG&E is unsure to which structure the decision refers: the large/small customers rate differential which PG&E proposed in Exhibit 139, or the illustrative declining block structure which PG&E filed in response to the ALJ's September 9, 1987, ruling. There was no opposition to PG&E's request that we clarify that the proposal referenced in the decision is the one in Exhibit 139. We will grant PG&E's request.

E. Noncore Rate Design Issues

1. PG&E's Petition for Modification dated 1/13/88.

PG&E asks us to clarify that the existing end-use priority system should continue in place, pending the Commission's further consideration of how to implement the priority charge concept. This clarification was not opposed, is reasonable, and we will adopt it.

2. CMA's Petition for Modification dated 2/25/88.

The petition for modification filed by CMA on February 25, 1988, raised three issues:

1. Calculation of D-1 demand charges for P-2b and G-IND customers in PG&E Advice Letter No. 1453-G.
2. Making negotiated contracts public.
3. Calculation of customer charges.

a) Calculation of D-1 Demand Charges.

It is our understanding that PG&E intends to modify its AL No. 1453-G to resolve the first issue concerning the arithmetical calculation of demand charges. PG&E apparently will use SoCal's method to calculate D-1 demand charges. SoCal's method has not been protested, to our knowledge. Therefore, action does not appear to be required on this issue.

b) Public Notice of Negotiated Contracts

Decision No. 87-03-044 ordered that contracts for noncore transmission service less than five years in length should be submitted to our Commission Advisory and Compliance Division (CACD), which would then make the contracts available as required. CMA is concerned that neither D. 87-03-044 nor D. 87-12-039 makes it clear exactly when the contracts must be filed with us. Also, CMA would like the utilities to make the contracts available for inspection at several different utility district offices.

We are not sure that a petition for modification of D. 87-12-039 is the proper forum to make such a request. However, we do feel strongly that no useful purpose would be served by placing unnecessary constraints on the public availability of these contracts. Such constraints merely increase transaction costs for gas customers. Thus, in the interest of expediency we will clarify D. 87-12-039 by adding an additional paragraph to require that the utilities will file with our CACD each negotiated contract for transmission service with a duration of less than five years; these filings shall be made within five days of the date of contract execution. [1] At this point the utilities should also make the contract available for public inspection at their general offices. Within ten days of execution the contract should be made available at the utilities' district offices.

c) Calculation of Customer Charges.

CMA notes the D.87-12-039 is ambigous regarding the calculation of customer charges for noncore customers. Our prior decisions were clear that a prior twelve month period would be used in the calculation of customer charges. However, CMA points out that the twelve month period could be a "set" historical period or a moving twelve month average. If a set period were used it appears that the customer charge would be established once each year and would not change during the year. On the other hand, with a twelve month moving average, the customer charge could be more responsive to the customer's immediate prior consumption level.

CMA alleges that PG&E is using the twelve month moving average whereas SoCal is using the "set" historical method. CMA supports the PG&E method and implicitly requests that whatever method is adopted be consistent for both utilities. TURN also supports a consistent method for both utilities. No parties filed in opposition to these requests.

The calculation of the D-1 demand charge relies on a twelve month moving average. The twelve month moving average will also result in more responsive customer charges. We will provide that the customer charges for noncore customers be based on a twelve month moving average.

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1 As ordered in D. 86-12-009 (p. 41), the utilities must file for our review and approval transmission contracts with terms of five years or longer.

3. DGS's Petition for Modification dated 1/12/88.
4. SDG&E's Petition for Modification dated 1/26/88.

The state Department of General Services (DGS) filed a petition for modification which raises two issues that were not also subjects of its petition for rehearing, which we dealt with in D. 88-03-041.

DGS asks us to require the utilities to post their noncore WACOG prices for the following month 5 to 10 days in advance of the dates on which interstate transport nominations are due. DGA argues that such advance notice will give customers time to shop around for the best price. DGS also proposes a true-up mechanism for the noncore WACOG.

PG&E opposes the posting requirement, stating that due to the timing of spot gas bids, it cannot determine the next month's noncore WACOG until very late in the month. PG&E is not opposed to DGS's noncore WACOG true-up mechanism, so long as the amortization of true-up balances can be extended beyond the next month if market conditions require.

SoCal states that as a matter of policy, it posts its noncore WACOG as soon as it is available, and argues that a posting requirement will not necessarily make it available any sooner.

DGS has not persuaded us that there is a significant problem with the current system for posting monthly noncore WACOGs. We will deny this request.

Both SDG&E and DGS offer proposals for non-core WACOG true-up. The DGS's proposed noncore WACOG true-up mechanism appears to be consistent with what we discussed in more general terms on p. 107 of the decision. We see no reason to make the decison any more specific on this issue, on which there was no dispute.

The SDG&E proposal is unclear, but our discussion of the DGS proposal above should resolve any uncertainty regarding our intention.

Finally, DGS asks us to delay the date for implementing rates "until 30 days after the Commission has issued decisions on storage unbundling, priority charges and access to interstate storage (sic)." In the alternative, DGS suggests an initial exemption from the minimum one-year term and the switching ban for core election. DGS bases this request largely upon the recent schedule revisions in I. 87-03-036, arguing that the issues in that investigation need to be decided before a complete package of services would be available to customers. The utilities and DRA oppose this request.

We will deny DGS's request for a delay in the implementation date. We agree fully with the utilties and DRA that the program adopted in D. 87-12-039 is fully capable of operating pending a decision on the issues in I. 87-03-036. The unresolved issues in I. 87-03-036 are largely procurement issues, and we remind all parties that May 1, 1988, is in no way a deadline for making long-lasting procurement choices. As SoCal notes, parties worried about the impact of unresolved storage and procurement issues are free to negotiate a short term transportation contract, and to procure gas themselves or from the noncore portfolio, to carry them until decisions are issued in I. 87-03-036.

5. SCUPP's Petition for Modification dated 3/9/88.

The Southern California Utility Power Pool and Imperial Irrigation District (SCUPP) ask us to reject SoCal Gas' attempt to impose a "new and excessive" transmission charge for UEG igniter fuel. This issue centers upon the following language in D. 87-12-039:

> D. Igniter Fuel Status
>
> Only PG&E raised this as an issue. Its recommendation is that this type of fuel, currently classified as P2A, be classified as core for transportation. This usage fits our basic definition of core service -- no alternate fuel

> capability -- and will be classified as core service.

D. 87-12-039, at 100. SoCal Gas' February 1, 1988 Advice Letter No. 1767 proposes a separate 32.667 cents per therm igniter fuel volumetric transmission rate for UEG customers. SCUPP filed the instant petition because it believes that this charge, which is equal to the average core transmission rate, conflicts with our statements about the rates to be charged to UEG customers and about the volumes that are to be included in the UEG Tier I. SCUPP contends that in D. 86-12-010 we decided to treat UEG load as noncore for transmission, with the full range of noncore procurement options. Additionally, in D. 87-12-039 we essentially continued the two-tiered UEG rate design first approved in D. 86-08-082; this rate design includes igniter fuel volumes in Tier I. The Tier I transmission rate is a noncore rate. SCUPP notes that the only testimony in the implementation proceeding concerning core treatment of igniter fuel was PG&E's testimony that it proposed to treat the igniter fuel for Southern California Edison's Coolwater complex as core transmission volumes. There was no examination of the igniter fuel volumes to which SoCal applies its rate, and no discussion of the fact that treating these volumes as core would mean that UEG customers would be bearing distribution system fixed costs. We have determined that UEG customers should not be allocated such costs, since they receive service at the transmission level. SCUPP concludes that the extreme uncertainty surrounding the imposition of a core transmission rate for igniter fuel, especially for SoCal Gas' UEG customers, argues in favor of specifying that such a charge should not apply at this time to SoCal's UEG customers.

SoCal's response disagrees with SCUPP's argument that we intended all UEG load to be noncore for transmission. SoCal cites page 16 of D. 86-12-010: "The P-1 and P-2A load of a multiple use customer will still be considered core, but will be eligible for transmission-only service and all utility procurement options."

Igniter fuel has a P2A priority. SoCal feels that it has appropriately followed D. 86-12-010 and D. 87-12-039 in establishing a core rate for the transmission of P-2A igniter fuel. SoCal does admit that, unlike PG&E, it did not include igniter fuel volumes as core load in its cost allocation. Thus, the imposition of its igniter fuel charge would result in overrecovery of $7.7 million annually from UEG customers. SoCal proposes several means of dealing with this overrecovery, including crediting the excess revenues to either the UEG class or to the core, or redoing the cost allocation with core treatment of igniter fuel volumes.

SoCal has correctly interpreted our intent in both D. 86-12-010 and D. 87-12-039. Although the great majority of UEG usage is noncore, igniter fuel usage does meet our definition of core load for transmission: P2A priority with no feasible alternative fuel capability. Thus, UEG customers are "multiple use" customers as discussed in D. 86-12-010, and the core portion of their usage should be charged a core transmission rate. However, SCUPP has highlighted how little attention this issue received in this case, especially with respect to SoCal's UEG rates. The exact mechanics of how igniter fuel volumes should be determined and treated in SoCal's rate design received no scrutiny at all. SCUPP's point is well taken that the allocation of core distribution system fixed costs to igniter fuel use may be inappropriate. Thus, allocating excess igniter fuel revenues back to the core may overcharge UEG customers. In addition, we have repeatedly resisted breaking new ground or revisiting old issues on cost allocation. Given this admittedly confused situation, we think that the best solution is to adopt SCUPP's request now, while giving SoCal's UEG customers notice at this time that we will treat igniter fuel use as core load for cost allocation and rate design purposes in SoCal's first cost reallocation proceeding. Until then, SoCal should eliminate its separate igniter fuel transmission charge. PG&E's tariff provisions on igniter fuel are reasonable, given that the issue was covered in PG&E's testimony.