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Decision 88-03-041 March 9, 1988

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)

ORDER MODIFYING DECISION 87-12-039 AND DENYING REHEARING

On December 9, 1987, the Commission issued Decision (D.)87-12-039. This decision established rates to implement the policy decisions which the Commission had made in December 1986, in D. 86-12-009 and 86-12-010, concerning natural gas rate regulation in California. Applications for rehearing were filed by four parties: Hadson Gas Systems (Hadson), California Edison Company (Edison), California Department of General Services (DGS), and California Manufacturers Association (CMA). Responses to these applications were filed by the Commission's Division of Ratepayer Advocates (DRA), Southern California Gas Company (SoCal), Toward Utility Rate Normalization (TURN), and Pacific Gas and Electric Company (PG&E). In addition, the following parties filed petitions for modification of D.87-12-039: SoCal (two separate petitions), PG&E, San Diego Gas & Electric Company, DGS, City of Palo Alto, City of Long Beach, TURN, California Hotel and Motel Association, and Hadson. Numerous responses to the petitions for modification were filed, and several parties filed responses to the responses.

We have considered each and every allegation raised in the applications for rehearing and the responses thereto, and are of the view that sufficient grounds for granting rehearing have not been shown. However, our further review has indicated that we should clarify and modify our decision in several respects. We will indicate these changes as we discuss the allegations raised by the various parties. We will also deal in this order with several of the petitions for modification which have been filed; the remainder of the petitions for modification will be resolved in a future order.

Applications for Rehearing.

Hadson. Hadson first argues that the core-elect price adopted by the Commission in D.87-12-039 is unjust, unreasonable, and discriminatory, in violation of P.U. Code Sections 451 and 453. This is because the Commission has failed to consider what costs are gas costs in deriving the core WACOG, and has arbitrarily excluded gathering and transportation costs from the calculation. The resulting core-elect gas price is not representative of a competitive market price.

For example, the Commission has excluded gathering costs from the cost of California gas in deriving PG&E's core-elect price. Those gathering costs are allocated to the transmission rates of all customers. But, Hadson argues, the only way that noncore customers get the benefit of this is by electing into the core. Those who don't make such an election but buy gas independently must pay gathering charges twice: as a pass-through charge from their broker/supplier, and in the transmission charge assessed by PG&E. Hadson similarly objects to the exclusion from core procurement prices of pipeline transport charges for Canadian gas; gathering and/or transport charges for El Paso and Rocky Mountain gas; and pipeline demand charges for PITCO volumes, which volumes are all assigned to the core. Hadson finally challenges the Commission's conclusion that SoCal's California gas cost is "excessive," thus justifying $13.7 million in transition costs.

Hadson claims this gas cost is a result of a border pricing formula; if it is excessive, other supplies must be also.

Hadson contends that in setting up cost allocation such that all customers, including those who buy gas from independent sources, have to pay for the gas utilities' substantial acquisition and marketing costs, the Commission is not only unduly discriminating against noncore customers who don't become core-elect, but is also condoning potentially serious anticompetitive consequences, i.e., the risk that competition among sellers to end users will be destroyed. Hadson alleges that Northern California Power Agency v. PUC (1971) 5 C.3d 370 (NCPA), holds that the Commission cannot lawfully implement its program without considering and making findings and conclusions on such anticompetitive effects.

PG&E, SoCal, and TURN correctly argue that the issues Hadson raises should have been raised in response to the Commission's December 1986 decisions, which effectively determined cost allocation.[1] These decisions have long since become final. Hadson's arguments, which in effect advocate revisiting of the Commission's cost allocation determinations, will be denied. In taking this action, however, we will review and expand upon some of the underpinnings for the allocation determinations we made in 1986.

As a general proposition, we concluded that all present customers, regardless of the services they choose, receive substantial benefit from the fact that a local distribution company has developed to the extent it has today. The utilities' structural and contractual relationships developed the way they did because the utilities procured gas for all customers. Moreover,

1 See, e.g., D.86-12-009 at 32, 53 (core-elect procurement charge to include only commodity gas costs; portion of interstate pipeline demand charges to be allocated to noncore customers; default noncore transmission rate to be the same regardless of procurement option chosen by the customer) and D.86-12-010 at 102-103 (allocation of PITCO commodity gas costs and Pan Alberta pipeline demand charges.)

today's low priority customers are still deriving benefits from the system, even though these benefits may exceed their present needs. It logically follows that all customers should continue to pay the unavoidable costs still being incurred as a result of the evolution of the utility structure, at least during the transition to reduction of excess capacity and configuration of the industry such that all customers can choose just what level of service they desire and be allocated costs accordingly.

We concluded that "unavoidable 'common costs' associated with the transition to a more competitive market and not directly assignable to any particular customer class" should be spread equitably to both procurement and transmission-only customers. D.86-12-010 at 96. One of the classes of fixed costs to be treated in this way was fixed pipeline demand costs, which were incurred to bring gas into the system to provide basic service and peak reliability. We also specifically found that PITCO costs should be treated similarly to other pipeline demand costs. Such treatment would be easier to implement, and might increase usage and corresponding revenues from the noncore class. Moreover, because the allocation of these charges fairly evenly between core and noncore markets reflected the current excess capacity situation, we did not feel that much could be gained, in this interim period, by examining one specific demand charge, e.g., PITCO, to see how much it exceeded current market value. Id. at 102-103.

We similarly determined that during this interim period, California gas gathering costs should be spread equally to all customers through inclusion of those costs in the transmission rate. We most recently set forth our reasons for this treatment, as well as affirming it, in D.87-05-069. In that decision we recognized, however, that our current treatment of gathering costs may not be fully consistent with our new unbundled rate structure, and called for further study of this issue. We directed our staff to report to us on the scope of the issues involved in unbundling and deaveraging the costs of the gathering systems of the major gas utilities, which we will use as the basis for further evaluation of the issue of recovery of gathering costs. D.87-05-069 at 76-77, Ordering Paragraph 6.

We note, in addition to the above, that transmission-only customers may still experience direct benefits from the above classes of costs. For example, should their independently-procured gas supply become unavailable, they can return to the utility for gas. For all of the reasons stated, we reaffirm our treatment of pipeline demand costs and gas gathering costs.

Hadson secondly argues that the Commission's adopted program gives the utilities an unfair marketing advantage, to the extent they have the exclusive use of information on customer characteristics that would be valuable to anyone intending to market gas to noncore customers. Moreover, Hadson claims they are in a position to unfairly tie their transmission monoply to core-election, both because of the price factors discussed above, and because they can negotiate discounted transmission rates only for those customers who elect into the core.

On the use of information, PG&E responds that a similar argument involving the use of customer lists was rejected by the 9th Circuit in a 1986 decision (Catlin v. Washington Energy Co. (9th Cir., 1986) 791 F2d 1343, 1348); SoCal and TURN concur, and add that the fact that utilities have proprietary lists of their own customers will be no impediment to the ability of end use customers to explore their procurement options with independent gas suppliers, including Hadson.

In the Catlin case, the court held that the exclusive use by the merchandising division of a local gas distribution utility of the utility's customer list to market certain energy saving devices was not an unlawful abuse of monopoly power, under either the federal antitrust laws or public utility statutes of the State of Washington. It was, rather, a benefit of size and business integration. Certainly here, a similar conclusion must be drawn. Hadson has not shown that the gas utilities will make use of any exclusive customer information that they possess in an anticompetitive or unreasonably discriminatory way.

We similarly find no merit to Hadson's preferential discount argument. First, we specifically caution against such a practice at page 7 of D.87-12-039. Second, SoCal makes several points concerning interstate pipeline demand charges, and interstate transportation charges in connection with purchase of spot supplies, which run directly counter to any argument that SoCal has any competitive cost advantage over independent broker/suppliers in selling gas to noncore customers. At the very least, these arguments cast doubt on Hadson's position. Third, we consider it extremely unlikely that the gas utilities have such an incentive in the context of the Commission's program, where the utilities collect margin <u>not</u> through gas sales but through transmission of gas. While they have other incentives for discounting, ensuring gas sales does not appear to be one of them.

Finally, the responding parties correctly point out, and we reiterate, that the Commission's program is still in the early stages of deregulating the procurement function. Compared to several years ago, enormous progress has been made in opening up the California procurement market to independent broker/suppliers such as Hadson. Moreover, while cost allocation has been resolved in terms of initial implementation of the program, it will certainly be reexamined in the future, after some experience has been gained under the rates set by D.87-12-039.

<u>Edison</u>. Edison contends that the Commission, in D.87-12-039, contravened "fundamental notions of fairness and due process" by modifying the stipulation signed by SoCal, PG&E, SDG&E, DRA (then PSD) and TURN in October 1986 ("Stipulation for Transition Period in Natural Gas Regulatory Procedure") to provide that SoCal's first reallocation filing will be no sooner that March 15, 1989. Edison argues that had it had notice that the Commission intended to make this modification, it would have vigorously protested, on the grounds that the rates which will be in effect from May 1, 1988 to June 30, 1989 will be totally outdated and inappropriate. Edison claims the Commission is bound by P.U. Code Section 1708 (mistakenly cited by Edison as 1705) to have hearings before modifying a decision (D.86-12-010 approved the stipulation

in its entirety; thus "modification" of it now constitutes a modification of that decision as well). Edison finally argues that DRA and TURN, in advocating the change the Commission made, have violated the terms of the stipulation because they did not meet with the other signatories before seeking the modification.

Edison's arguments are completely misplaced on this issue. DRA's response puts it cogently:

> "The Stipulation simply does not provide for a SoCal cost allocation in the Spring of 1988. ... When this portion of the stipulation [relating to SoCal's cost allocation filing being due no later than March 15 of each year] is read in conjunction with the other provisions, the only logical conclusion is that the first annual cost allocation was intended to occur <u>after</u> the new rates set by the implementation decision took effect. Since the new rates don't take effect until May 1988, both TURN and DRA recommended that the Commission clarify that SoCal's first annual cost allocation occur in the spring of 1989."

DRA Response to Apps/Rhg at 7.

DRA goes on to cite specific paragraphs of the stipulation which support its and TURN's position. SoCal's and TURN's responses are basically in agreement with DRA.

We will modify the decision to clarify that the stipulation is not being modified, but merely being logically interpreted.

Edison secondly argues that by changing the cost allocation schedule, the UEG rates adopted in D.87-12-039 will be unlawful and unreasonable because they will be based not on the "best forecast available" as required by the stipulation, but on an outdated UEG sales forecast. As such, Edison claims these rates will overly burden electric ratepayers and are likely to result in SoCal's uncollecting margin from its UEG customers.

We agree with DRA that Edison's claim has no merit. DRA argues that the "best forecast available" language refers to the subsequent cost allocation proceedings and not the implementation decision establishing initial rates. DRA further points out that the adopted forecast, which Edison supported, was based on the best estimates then available, and is generally consistent with the adopted rates.

As DRA points out, the regulatory process is by its nature relatively slow. It can always be argued that the forecast used to adopt rates is a stale one. The fact that Edison has now generated a newer forecast does not, in the absence of a showing of evidentiary defects in the prior forecast, warrant a finding that the adopted rates are unreasonable. In addition, Edison's newer forecast is not part of the record and has not been subjected to cross examination.

Finally, we note that in the not-too-distant past, we set future rates based on the results of an historical test year. Such rates have never been found to be unlawful on that basis.

CMA. CMA alleges legal error concerning three aspects of the demand charge provisions contained in D.87-12-039. CMA first argues that customers who cease taking service before the implementation date must only be liable for existing demand charges rather than demand charges under the new program, in order that those customers have some bargaining leverage. We believe CMA's position reflects the intent of the decision, and we will clarify it accordingly.

CMA secondly argues that even if a customer has been buying gas under a rate schedule containing a demand charge and continues to buy gas as a default customer after the new rate design is implemented, the customer's use prior to the effective date of the new rate design should not be used to calculate the new demand charges. CMA states: "In short, CMA believes that the position expressed in D.87-07-044 and reiterated in D.87-12-039 is wrong." CMA App. at 4. PG&E supports CMA's position, but points out that such a modification would require a recalculation of rates and billing determinants. SoCal, DRA and TURN argue against this as being simply a rehash of arguments CMA has made numerous times before; they also point out that the demand charge structure was clearly set forth in D.86-12-009, and that as such, CMA had adequate notice of how it was to work.[2]

We agree that we have seen and rejected CMA's argument on this point before, and we do so again.

CMA's third concern is over the one-year ratchet provision for demand charges. CMA admits to previously expressing its view and sponsoring testimony supporting its position that the one-year ratchet "will cause many default customers either to minimize their gas usage or to leave the system entirely." CMA App. at 6-7. This is apparently because of hardships which will be suffered by those default customers who experience significant swings in usage, and subsequently, very high or low bills for periods of up to a year. CMA recommends that we resolve this concern, as well as the two discussed above, by allowing all customers to establish "reasonable contract demands for purposes of administering demand charges." CMA App. at 7. Such could be established seasonally or annually, and ratcheting could be required "only if the customer's monthly usage consistently exceeds the contractually established demand quantity." Id. If the Commission does not want to adopt this approach, it should subject default customers to the new demand charges only to the extent that they take gas on or after the effective date of the new rate design.

We will deny CMA's contract demand proposal. This is a proper subject for utility/customer negotiations.

DGS. DGS, a state agency as well as a cogenerator, raises three issues concerning the adopted cogeneration rates.

2 CMA also asserts, without argument or authority, that using a customer's past usage as a basis for calculating a future demand charge would constitute retroactive ratemaking. DRA correctly refutes this argument. While the method used to calculate the rate relies on historical usage, the rate is set prospectively to recover a portion of the utility's revenue requirement during the period the rates are in effect, and does not in any way attempt to recover utility costs incurred during a prior period.

DGS first argues that the adopted procurement rate for core cogenerators violates Section 454.4 because it does not insure that cogenerators receive a rate equal to or less than the rate charged the UEG class for gas used to generate electricity.[3]

The decision establishes a "true-up" mechanism which ensures that both core and noncore cogenerators pay a transmission rate which is no higher than the transmission rate paid by UEG customers. However, no such mechanism is adopted for procurement rates. Rather, the decision provides that core cogenerators will pay the same price for gas as UEG customers electing into the core portfolio, and noncore cogenerators (who qualify for noncore status like any other customer) will pay the same noncore portfolio price as noncore UEG customers who also buy from the utility's noncore portfolio. DGS argues that core cogenerators will be denied the rate parity guaranteed by the statute if the utility from whom they buy gas elects noncore service, because they cannot buy gas at the lower noncore rate.

TURN's cursory response appears to agree with DGS. Due to a misreading of the decision, PG&E argues that DGS' argument is moot.

DRA argues, on the other hand, that the statute requires only the treatment afforded by the decision. If the Commission were to adopt DGS' position, it would in effect be telling SoCal that when Edison elects service from the noncore portfolio, SoCal must charge no more to its cogenerators than the noncore price. The decision itself implies that this is no longer possible now that the procurement aspect of gas service has been deregulated. DRA argues further that the fact that UEG customers have the option of electing in and out of the core does not mean that the

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3 Section 454.4 provides, in relevant part:

> "The Commission shall establish rates for gas which is utilized in cogeneration technology projects not higher than the rates established for gas utilized as a fuel by an electric plant in the generation of electricity...."

Commission must create this same flexibility for all cogeneration customers, regardless of their ability to qualify for noncore status. The decision has allowed a parity rate for parity service; i.e., those UEG customers wanting the price and supply security of core election will opt for core procurement service at the same procurement rate paid by core cogenerators.

We affirm the approach we adopted in D.87-12-039. This approach assumes that the statute allows us the flexibility to take into account the distinction we have established between core and noncore customers, and the way that distinction translates into procurement options and accompanying procurement rates. In our view, it is not relevant that many if not most cogenerators will be unable to buy gas from the gas utility at as low a price as their UEG utility can, due to the fact that "core" cogenerators cannot become noncore customers for gas procurement. What is important is that they be given the same core portfolio price as core UEG customers if they are core cogenerators, and the same noncore portfolio price as noncore UEGs if they are noncore cogenerators.

We reject DGS' view that the statute does not allow consideration of the core-noncore distinction, and that no matter what we do in other areas of gas regulation, we are locked into offering to <u>all</u> cogenerators the lowest rate that is available to a UEG customer when buying gas from a gas utility. We do not believe that the Legislature intended to place that restriction on our regulatory authority.[4]

4 DGS makes the subsidiary argument that the Commission also violates Section 454.4 by equating UEC core usage with the rate used by UEG customers to generate electricity, because UEG core usage only involves the use of igniter fuel -- which doesn't generate electricity but only lights pilot lights. DRA and SoCal both challenge what they consider a narrow definition of igniter fuel. They argue that without igniter fuel, there is no generation of electricity; thus charging both core cogenerators and UEG customers the procurement rate for core volumes <u>is</u> rate parity, regardless of what point in the generation process the gas is being used. We agree with DRA and SoCal.

DGS secondly argues that Section 454.4 requires specification by the UEG utility of the percentage of gas purchased from core and noncore portfolios and delivered via self-procurement, early enough to allow cogenerators to select the same option. Otherwise, DGS argues, cogenerators have no opportunity to obtain the parity rates mandated by the statute. DGS also claims that the average self-procurement price should be disclosed, to permit parity rates and to avoid "negative arbitrage" in avoided cost/purchased gas cost prices. DGS argues that failure to require such notice from the utilities is unlawful not only because of the Section 454.4 problem, but because the Commission has failed to consider the anticompetitive aspects of allowing the utilities to elect procurement options "in secret," which is required by NCPA, supra.

DRA favors the UEG notice, arguing that unless noncore cogenerators are given some advance notice of the total UEG procurement package, they may well not be able to match the UEG cost of gas. DRA recommends that at a minimum, notice should be given at the time that UEG customers change their procurement options. Rather than require lengthy advance notice, which would not allow UEG customers to respond quickly to changing market conditions, perhaps the Commission could build a lag into the avoided gas costs used to set QF payments. But DRA does not advocate deciding this question now; rather, there is no evidence that a short lag will hurt cogeneration customers, especially if they follow a least cost purchasing strategy.

We will adopt DRA's recommendation for UEG notice. We will modify the decision to require notice to be given to cogenerators by the UEG utility, immediately after it determines its procurement percentages. Such notice should include the average self-procurement price.

DGS finally argues that the gas utilities' expressed intention of treating cogeneration facilities with standby boilers as two customers (presumably because such customers have two gas meters) for purposes of customer and demand charges will constitute the imposition of unjust, unreasonable and discriminatory rates.

This is because "[i]n general (except for supplemental firing in excess of cogeneration production), only one use of the gas would ever occur at any one time." DGS App. at 9.

PG&E and DRA dispute this charge. PG&E argues that cogeneration facilities with separately metered standby boilers involve two sets of customer-related facilities and services, thus two charges are appropriate. DRA appears to agree, arguing that the Commission's adopted rate design, based on a customer's assignable system cost responsibility on a per-meter basis, cannot assess system effects of multiple gas uses at a single location.

SoCal and TURN, however, believe that DGS' position has merit in those cases where the standby boiler system only operates to the extent that the cogeneration system is not operating.

We will adopt the SoCal/TURN position as the more equitable one. We will require the gas utilities to treat cogeneration facilities with standby boilers as one customer for purposes of assessing customer and demand charges, providing the cogeneration customer has signed an affidavit to the effect that its boiler system only operates when the cogeneration system is not operating.

<u>Petitions for Modification.</u>

<u>SoCal's Second Petition for Modification.</u> On February 16, 1988, SoCal filed a second petition for modification of D. 86-12-009 and D. 87-12-039. SoCal asks us to require that wholesale customers obtain gas for their core customers from the core portfolio of their serving utility. SoCal also requests that UEG customers be required to purchase their Tier I volumes from the core portfolio. SoCal would be satisfied if these requirements were instituted on a temporary basis, pending the outcome of further hearings to determine if they should be made permanent.

SoCal asserts that, absent the imposition of these requirements, there will be a significant negative impact on SoCal's remaining core customers, without any offsetting benefits for wholesale and UEG customers. SoCal notes that wholesale core and Tier I UEG requirements, in an average year, approach 300 MMcfd. The addition of this load to the core portfolio would allow

SoCal to include additional volumes of discretionary purchases in the core portfolio. SoCal asserts that these purchases would likely be at prices below the pre-existing core WACOG, and thus would reduce the core WACOG, to the benefit of all core customers. SoCal also notes that with a larger core portfolio, if it purchased additional supplies from El Paso and Transwestern, the per unit cost of gas from these pipelines would fall, and SoCal's exposure to take-or-pay costs passed through by the pipelines would likely decline. SoCal says that it is unclear whether take-or-pay costs accrued and billed after May 1, 1988, will be spread equally among all utility customers, or levied on just core customers; thus, increased take-or-pay costs could fall on just core customers. Finally, SoCal believes that as a practical matter it retains the obligation to serve wholesale core and UEG Tier I load. Thus, even if wholesale and UEG customers have procurement flexibility for this load, SoCal plans to incur additional costs in order to "backstop" these loads. SoCal submits that these extra costs can be avoided by requiring core procurement for these loads.

SoCal sees no positive benefits from allowing wholesale and UEG customers procurement flexibility for these loads, which SoCal points out are fundamentally "core" in nature -- i.e. there are no feasible alternatives to using gas. SoCal has provided the utility/public service function of procuring gas for these loads for many years, and sees no evidence that wholesale customers or the electric utilities would do a better job at that task. In addition, SoCal argues that such a shift in responsibilities would not produce any more competition than currently exists in California's restructured gas industry.

We have considered SoCal's request carefully, and have found nothing more in it than a very late attempt to stem a tide that is already running at full flood. First, implicit in SoCal's request is an assumption that its wholesale and electric utility customers might not recognize their own new public service responsibilities. We disagree strongly with SoCal's assertion that the change in SoCal's obligation to serve which accompanies our new program is merely a change "in theory", with little practical import. In fact, the wholesale customers and the electric utilities will now have important new public service responsibilities in their purchases of gas for "core" needs. We think that SoCal should recognize that SDG&E and Southern California Edison, and the municipal utilities, are fully as accountable for the efficient discharge of their public service responsibilities as is SoCal. SDG&E and SCE must justify to this Commission the reasonableness of their gas purchases, including the purchases of independent supplies to meet core loads. We doubt strongly, for example, that SDG&E is ready at this time to rely on spot gas, or even on its own procurement of longer-term supplies, to meet more than a small portion of the requirements of its core customers. This is especially true given the fact that our hearings on the unbundling of storage are still underway; the Commission has issued no decision yet on SDG&E's request for independent access to a portion of SoCal's storage capacity. In addition, the FERC has yet to take the necessary steps which might allow SDG&E access to firm interstate pipeline capacity. And the recent gas curtailments in southern California should provide ample evidence of the perils of relying on short-term gas supplies. We are certainly concerned that SDG&E and SCE purchase firm, reliable supplies to meet those needs for which there is no alternative to the use of gas, and we will scrutinize the actions which they take toward that goal. We will also review carefully whether SoCal has purchased excess core supplies to "backstop" loads that it is no longer obligated to supply, and will not hesitate to refuse to recognize such excess costs in rates.

Clearly, the SoCal core portfolio is a logical and convenient source of dedicated, reliable gas supplies. Especially in the near term, SDG&E and SCE may very well purchase most if not all of their "core" requirements from the SoCal core portfolio. Yet SoCal's core portfolio may not be the only source of reliable supplies for these loads, and we decline SoCal's request to make it the only source by regulatory fiat. We disagree with SoCal's assertion that its request will not decrease competition: SoCal's proposal would preclude suppliers other than SoCal from competing to provide firm gas supplies to SDG&E, Long Beach, and the electric utilities. Rather than seeking a regulatory shelter from competition, we would prefer to see SoCal devote its energy to assembling a core portfolio that can compete with other gas suppliers for these core loads. Perhaps SoCal should begin by reassessing its "must take" obligations which it says so limit its flexibility in purchasing core supplies.

SoCal argues that the smaller the core portfolio, the higher the average price charged by its pipeline suppliers and the greater the take-or-pay liabilities which the pipelines will seek to pass through to the California utilities. This is not a new problem; it is a concern which we have faced since wellhead deregulation and the increasing availability of transportation allowed the utilities and their customers dramatically increased flexibility in procuring gas supplies. In the past, the utilities, including SoCal, have rationalized lower takes of pipeline sales gas because the resulting take-or-pay liabilities were more than offset by the savings in gas costs. Now SoCal apparently feels that this is not true for firm supplies, asserting that "there is no evidence that [the wholesale and UEG] customers can obtain supplies as firm and stable in price as SoCalGas' core portfolio gas at a price much, if any, lower than SoCalGas' core portfolio WACOG." However, if SoCal's core portfolio, <u>including</u> pipeline sales gas, is indeed the most economical firm supply available, then SoCal should be confident that the wholesale and UEG customers <u>will</u> elect into SoCal's core portfolio.[5]

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5 SoCal states that core customers alone may have to bear take-or-pay liabilities accrued and billed after the May 1, 1988, implementation date. We find no support for that statement in either D. 86-12-009 or D. 87-12-039. Our current policy, which we expect to continue after the implementation date, is to treat as transition costs all take-or-pay liabilities resulting from gas purchase contracts or arrangements which took effect before the division of the supply portfolio in D. 87-12-009 and 010. We have no reason to believe that California's pipeline suppliers will not

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For the above reasons, we will deny SoCal's proposed modification to D. 86-12-009 and D. 87-12-039.

PG&E's Petition for Modification of D. 87-12-039. PG&E's petition raises four issues, only one of which we will resolve at this time.

PG&E also asks us to clarify our cogeneration rate design. PG&E cites language on page 102 of D. 87-12-039 which it says implies that the cogeneration class is to be "folded into" the commercial and industrial classes for rate design purposes. PG&E says that this is inconsistent with the decision's later adoption of SoCal's proposal to merge cogeneration and UEG customers into one UEG/Cogen class. PG&E is also unclear on the structure of the "otherwise applicable" transportation rate which will be the basis for one of the two bills calculated each month for cogeneration customers. PG&E appears to ask us to create a "noncore cogeneration transportation rate", set this rate equal to the average UEG rate, and use this rate as the "otherwise applicable" rate. This rate would have a structure similar to other industrial and UEG rates. Finally, PG&E says that under this interpretation the cogeneration shortfall will diminish, but not disappear; PG&E recommends that we establish a tracking account to accumulate the shortfall between cost reallocations.

No party fully supported PG&E's requested clarification. SoCal, for example, believes that PG&E's request is based upon a misunderstanding of what constitutes the cogenerators' "otherwise applicable" rate. SoCal states that the "otherwise applicable" rate is "the industrial or commercial transmission rate which would apply to the cogenerators' heating or process needs if he had no

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continue to accrue liabilities under such contracts after May 1, 1988, nor can we forsee any reason to modify after that date our current policy for the allocation of transition costs. Transition costs are allocated to all customer classes on an equal cents per therm basis.

cogeneration equipment." There is no separate noncore cogeneration rate, as that rate has been merged into the rate of the combined UEG/Cogen class. There is in addition no need to clarify the structure of the "otherwise applicable" rate, as it is just the structure of the default tariff which would apply to the customer's heating or process usage in the absence of cogeneration. SoCal notes that it has proposed a purely volumetric cogeneration rate, to allow the rate to maintain absolute parity with fluctuations in the average UEG rate. Finally, SoCal feels that the decision accurately notes that there will be no "cogeneration shortfall" so long as the rate for the UEG/Cogen class is less than those for other industrial and commercial classes. The DRA concurs with SoCal.

We have reviewed this issue carefully, and have concluded that SoCal has accurately characterized the cogeneration rate structure which D. 87-12-039 established. PG&E fundamentally misunderstands what constitutes the "otherwise applicable" rate. In a nutshell, here is how cogeneration transportation rates will be designed and billed: for cost allocation and default rate calculation purposes, cogeneration throughput will be merged with UEG volumes into a single UEG/Cogen customer class. Then each month, the utility will calculate two bills for transmission service for each cogeneration customer: one applying the actual average transportation rate paid by UEG customers, lagged by 60 days; and one applying the industrial or commercial transportation rate which that customer would pay for heating or process needs if it had no cogeneration equipment (the "otherwise applicable" rate). The customer will pay the lower of the two bills. There is no "cogeneration shortfall" unless the "otherwise applicable" rate is less than the UEG rate. D. 87-12-039 needs no further clarification on this issue. PG&E must refile its tariff sheets to reflect accurately the cogeneration rate structure established in that order.

We do concur with PG&E that if a cogeneration shortfall does materialize, the utility should establish an account to track the shortfall so that it can be reallocated in the next cost allocation proceeding.

<u>Hadson's Petition for Modification of D. 87-12-039.</u> Hadson filed a Petition for Modification of D. 87-12-039 on February 22, 1988. In its Petition, Hadson seeks to expand the function of the priority charge previously adopted by the Commission to ration capacity on the utilities' systems. Briefly, Hadson seeks to use the priority charge to allocate interstate pipeline capacity by using the charge to allocate capacity shortages on either the intrastate or interstate pipeline systems.

We note at the outset that the precise operation of the priority charge mechanism has been deferred to the ongoing procurement hearings in I. 87-03-057. For that reason alone, we would decline to undertake such a dramatic expansion of the priority charge mechanism without the opportunity to obtain the views of other parties. However, careful consideration of the Hadson proposal reveals even more difficult barriers to its adoption.

First, the Federal Energy Regulatory Commission (FERC) is clearly entrusted with the jurisdiction to regulate the transportation of natural gas over interstate pipelines under the provisions of Section 1b of the Natural Gas Act (15 U.S.C. §717b). The FERC has imposed its own system for regulating the priority of gas shipments over interstate pipelines in the form of a "first come, first served" policy, adopted in the FERC's Order No. 436, (<u>Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol</u>, 50 Fed. Reg. 42408 (October 18, 1985), FERC Regulations and Preambles ¶30,665 at 31,516.)

While Hadson blithely assumes that the California priority charge could be used to determine which customer is curtailed first in a shortage of interstate capacity (the customer paying the lowest California priority charge), such a system provides no assurance that the next shipper in the FERC's first come, first served queue will be next in line under the California priority charge system. We foresee substantial difficulty in coordinating the two priority systems. If, for instance, shippers exercised their federal priority rights to deliver gas to the interstate pipeline, yet were refused delivery in California because of the operation of the California priority charge, both the interstate pipeline and the utility would face a future obligation to deliver gas without any assurance as to when such delivery would be possible depending upon the demand for transportation and the priority charges paid by competing customers.

Hadson asserts that the key to making its proposal work is the adoption of reasonable balancing provisions. Yet under the example described above, a customer could quickly build up substantial balances of undelivered gas. We are not prepared to judge that either the interstate pipelines or the utilities are capable of managing such a balancing arrangement in the face of conflicting or incompatible state and federal pipeline priority systems. Nor are we inclined to precipitate a legal challenge to federal regulation of interstate pipeline capacity allocation through the use of our priority charge mechanism. Accordingly we will decline to adopt Hadson's suggestion.

IT IS ORDERED that Decision (D.) 87-12-039 is modified as follows:

1. The discussion entitled "Allocation Factors" beginning on page 8 is modified to read:

> "D.86-12-009 adopted allocation factors to divide nongas costs among the core, noncore, and wholesale markets. We explicitly chose relatively 'flat' factors which tend to spread these costs more evenly over all markets. These factors recognize that the current system was built to serve all customer classes, and that all users should contribute to paying for the current excess capacity in the system.
>
> "As a general proposition, we concluded that all present customers, regardless of the services they choose, receive substantial benefit from the fact that a local distribution company has developed to the extent it has today. The utilities' structural and contractual relationships

developed the way they did because the utilities procured gas for all customers. Moreover, today's low priority customers are still deriving benefits from the system, even though these benefits may exceed their present needs. It logically follows that all customers should continue to pay the unavoidable costs still being incurred as a result of the evolution of the utility structure, at least during the transition to reduction of excess capacity and configuration of the industry such that all customers can choose just what level of service they desire and be allocated costs accordingly.

"We concluded that "unavoidable 'common costs' associated with the transition to a more competitive market and not directly assignable to any particular customer class" should be spread equitably to both procurement and transmission-only customers. D.86-12-010 at 96. One of the classes of fixed costs to be treated in this way was fixed pipeline demand costs, which were incurred to bring gas into the system to provide basic service and peak reliability. We note, in addition to the above, that current transmission-only customers may still experience direct benefits from the above classes of costs. For example, should their independently-procured gas supply become unavailable, they can return to the utility for gas.

"We have been asked on several occasions since D.86-12-009 and D.86-10-010 were issued to revisit our allocation factors, and in both D.87-03-044 and D.87-05-046 we have firmly refused to do so. For the reasons we have set forth above, we reiterate today our intention not to revisit this issue until, as stated in our December 1986 decisions, such time as the present excess capacity is reduced."

2. The following new paragraph is inserted after the last full paragraph on page 103:

"We will, however, require UEG customers to notify their cogeneration customers, immediately after they have determined their procurement packages, of the percentages of core, noncore, and self-procurement gas which they have included in the package. Each time the package changes, the UEG customer should provide new notice. This notice should include the average self-procurement price. This mechanism will assist noncore cogenerators in matching the UEG cost of gas."

3. The following paragraphs are inserted after the first full paragraph on page 104:

"On another subject, the California Department of General Services (the State) has raised the problem of the gas utilities' apparent intention to treat a cogeneration facility with a standby boiler as two customers for the purposes of assessing separate customer and demand charges. The State argues that this treatment ignores the use diversity between the two facilities; that the operation of the two facilities is inversely correlated, with only one use of the gas system occuring at any one time (with the exception of supplemental firing in excess of cogeneration production).

"We agree with the State that the more equitable approach to this situation is to treat cogeneration facilities with standby boilers as one customer for purposes of assessing customer and demand charges, providing the cogeneration customer has signed an affidavit to the effect that its boiler system only operates when the cogeneration system is not operating."

4. Section I at the top of page 110 is modified as follows:

"D.86-12-009 was clear in providing that the noncore default customers would be obligated for demand charges for a one year period. The remaining issue is whether customers taking no gas on the implementation date should also incur demand charges for a one-year period based on historical usage. As a matter of policy, we believe that it is fair to excuse customers not taking gas on the implementation date from demand charges based on historical usage if: 1) those customers fall under a rate schedule which does not currently contain a demand charge

> or 2) those customers have not used gas for the year prior to the implementation date. Customers who do not take gas on <u>or after</u> the implementation date of the new rate design will not be subject to the higher demand charges under that rate design, but will only be subject to demand charges under applicable rate schedules in effect prior to the implementation date."

5. The second to last sentence in the first full paragraph on page 116 is modified to read:

> "Therefore, consistent with logical interpretation of the stipulation, we will provide that the first annual reallocation filing that we will allow will be PG&E's September 15, 1988, filing."

6. The following new Findings are added to precede Finding 1 on page 118:

i. "We concluded in our December 1986 decisions that a) all present customers, regardless of the services they choose, receive substantial benefit from the structure and function of the local distribution company; and b) these benefits extend to low priority customers, even though they may exceed those customers' present needs or may constitute potential future benefits."

ii. "We further concluded that because of these benefits, all customers should continue to pay the unavoidable costs still being incurred as a result of the evolution of the local distribution company structure to its present state of excess capacity, at least until the excess capacity has been reduced and the industry re-formed such that customers may choose and will be allocated the costs of services to match their exact needs."

iii. "We finally concluded that unavoidable 'common costs' associated with this transition and not readily assignable to any given customer class, e.g., pipeline demand charges, should be spread equitably to both procurement and transmission-only customers."

7. New Ordering Paragraph 8 is added to read:

"Initially, and each time UEG customers change their procurement packages, they shall immediately notify their cogeneration customers of the percentages of core, noncore, and self-procurement gas which they have included in the package. This notice should include the average self-procurement price."

8. New Ordering Paragraph 9 is added to read:

"The gas utilities shall treat cogeneration facilities with standby boilers as one customer for purposes of assessing customer and demand charges, providing the cogeneration customer has signed an affidavit to the effect that its boiler system only operates when the cogeneration system is not operating."

IT IS FURTHER ORDERED that the applications for rehearing of D.87-12-039 as modified herein are denied.

IT IS FURTHER ORDERED that SoCal Gas' second petition for modification of D. 87-12-039, PG&E's petition for modification on the issue of cogeneration rates, and Hadson's petition for modification are denied. PG&E shall file a revised default tariff for service to cogenerators which reflects the correct interpretation of D. 87-12-039.

This order is effective today.

Dated March 9, 1988 at San Francisco, California.

STANLEY W. HULLETT
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

L/AKM/pds

HEX-4
EX-2

Decision 88 03 041 MAR 09 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)
	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)

ORDER MODIFYING DECISION 87-12-039 AND DENYING REHEARING

On December 9, 1987, the Commission issued Decision (D.)87-12-039. This decision established rates to implement the policy decisions which the Commission had made in December 1986, in D. 86-12-009 and 86-12-010, concerning natural gas rate regulation in California. Applications for rehearing were filed by four parties: Hadson Gas Systems (Hadson), California Edison Company (Edison), California Department of General Services (DGS), and California Manufacturers Association (CMA). Responses to these applications were filed by the Commission's Division of Ratepayer Advocates (DRA), Southern California Gas Company (SoCal), Toward Utility Rate Normalization (TURN), and Pacific Gas and Electric Company (PG&E). In addition, the following parties filed petitions for modification of D.87-12-039: SoCal (two separate petitions), PG&E, San Diego Gas & Electric Company, DGS, City of Palo Alto, City of Long Beach, TURN, California Hotel and Motel Association, and Hadson. Numerous responses to the petitions for modification were filed, and several parties filed responses to the responses.

We have considered each and every allegation raised in the applications for rehearing and the responses thereto, and are of the view that sufficient grounds for granting rehearing have not been shown. However, our further review has indicated that we should clarify and modify our decision in several respects. We will indicate these changes as we discuss the allegations raised by the various parties. The issues raised in the petitions for modification will be resolved in a future order.

Applications for Rehearing.

Hadson. Hadson first argues that the core-elect price adopted by the Commission in D.87-12-039 is unjust, unreasonable, and discriminatory, in violation of P.U. Code Sections 451 and 453. This is because the Commission has failed to consider what costs are gas costs in deriving the core WACOG, and has arbitrarily excluded gathering and transportation costs from the calculation. The resulting core-elect gas price is not representative of a competitive market price.

For example, the Commission has excluded gathering costs from the cost of California gas in deriving PG&E's core-elect price. Those gathering costs are allocated to the transmission rates of all customers. But, Hadson argues, the only way that noncore customers get the benefit of this is by electing into the core. Those who don't make such an election but buy gas independently must pay gathering charges twice: as a pass-through charge from their broker/supplier, and in the transmission charge assessed by PG&E. Hadson similarly objects to the exclusion from core procurement prices of pipeline transport charges for Canadian gas; gathering and/or transport charges for El Paso and Rocky Mountain gas; and pipeline demand charges for PITCO volumes, which volumes are all assigned to the core. Hadson finally challenges the Commission's conclusion that SoCal's California gas cost is "excessive," thus justifying $13.7 million in transition costs. Hadson claims this gas cost is a result of a border pricing formula; if it is excessive, other supplies must be also.

Hadson contends that in setting up cost allocation such that all customers, including those who buy gas from independent sources, have to pay for the gas utilities' substantial acquisition and marketing costs, the Commission is not only unduly discriminating against noncore customers who don't become core-elect, but is also condoning potentially serious anticompetitive consequences, i.e., the risk that competition among sellers to end users will be destroyed. Hadson alleges that Northern California Power Agency v. PUC (1971) 5 C.3d 370 (NCPA), holds that the Commission cannot lawfully implement its program without considering and making findings and conclusions on such anticompetitive effects.

PG&E, SoCal, and TURN correctly argue that the issues Hadson raises should have been raised in response to the Commission's December 1986 decisions, which effectively determined cost allocation.[1] These decisions have long since become final. Hadson's arguments, which in effect advocate revisiting of the Commission's cost allocation determinations, will be denied. In taking this action, however, we will review and expand upon some of the underpinnings for the allocation determinations we made in 1986.

As a general proposition, we concluded that all present customers, regardless of the services they choose, receive substantial benefit from the fact that a local distribution company has developed to the extent it has today. The utilities' structural and contractual relationships developed the way they did because the utilities procured gas for all customers. Moreover, today's low priority customers are still deriving benefits from the system, even though these benefits may exceed their present needs.

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1 See, e.g., D.86-12-009 at 32, 53 (core-elect procurement charge to include only commodity gas costs; portion of interstate pipeline demand charges to be allocated to noncore customers; default noncore transmission rate to be the same regardless of procurement option chosen by the customer) and D.86-12-010 at 102-103 (allocation of PITCO commodity gas costs and Pan Alberta pipeline demand charges.)

It logically follows that all customers should continue to pay the unavoidable costs still being incurred as a result of the evolution of the utility structure, at least during the transition to reduction of excess capacity and configuration of the industry such that all customers can choose just what level of service they desire and be allocated costs accordingly.

We concluded that "unavoidable 'common costs' associated with the transition to a more competitive market and not directly assignable to any particular customer class" should be spread equitably to both procurement and transmission-only customers. D.86-12-010 at 96. One of the classes of fixed costs to be treated in this way was fixed pipeline demand costs, which were incurred to bring gas into the system to provide basic service and peak reliability. We also specifically found that PITCO costs should be treated similarly to other pipeline demand costs. Such treatment would be easier to implement, and might increase usage and corresponding revenues from the noncore class. Moreover, because the allocation of these charges fairly evenly between core and noncore markets reflected the current excess capacity situation, we did not feel that much could be gained, in this interim period, by examining one specific demand charge, e.g., PITCO, to see how much it exceeded current market value. Id. at 102-103. Similar arguments as to reflection of benefits to all customers can be made for California gas gathering costs.

We note, in addition to the above, that transmission-only customers may still experience direct benefits from the above classes of costs. For example, should their independently-procured gas supply become unavailable, they can return to the utility for gas. For all of the reasons stated, we reaffirm our treatment of pipeline demand costs and gas gathering costs.

Hadson secondly argues that the Commission's adopted program gives the utilities an unfair marketing advantage, to the extent they have the exclusive use of information on customer characteristics that would be valuable to anyone intending to market gas to noncore customers. Moreover, Hadson claims they are in a position to unfairly tie their transmission monopoly to core-election, both because of the price factors discussed above, and because they can negotiate discounted transmission rates only for those customers who elect into the core.

On the use of information, PG&E responds that a similar argument involving the use of customer lists was rejected by the 9th Circuit in a 1986 decision (Catlin v. Washington Energy Co. (9th Cir., 1986) 791 F2d 1343, 1348). SoCal and TURN concur, and add that the fact that utilities have proprietary lists of their own customers will be no impediment to the ability of end use customers to explore their procurement options with independent gas suppliers, including Hadson.

In the Catlin case, the court held that the exclusive use by the merchandising division of a local gas distribution utility of the utility's customer list to market certain energy saving devices was not an unlawful abuse of monopoly power, under either the federal antitrust laws or public utility statutes of the State of Washington. It was, rather, a benefit of size and business integration. Certainly here, a similar conclusion must be drawn. Hadson has not shown that the gas utilities will make use of any exclusive customer information that they possess in an anticompetitive or unreasonably discriminatory way.

We similarly find no merit to Hadson's preferential discount argument. First, we specifically caution against such a practice at page 7 of D.87-12-039. Second, SoCal makes several points concerning interstate pipeline demand charges, and interstate transportation charges in connection with purchase of spot supplies, which run directly counter to any argument that SoCal has any competitive cost advantage over independent broker/suppliers in selling gas to noncore customers. At the very least, these arguments cast doubt on Hadson's position. Third, we consider it extremely unlikely that the gas utilities have such an incentive in the context of the Commission's program, where the utilities collect margin not through gas sales but through transmission of gas. While they have other incentives for discounting, ensuring gas sales does not appear to be one of them.

Finally, the responding parties correctly point out, and we reiterate, that the Commission's program is still in the early stages of deregulating the procurement function. Compared to several years ago, enormous progress has been made in opening up the California procurement market to independent broker/suppliers such as Hadson. Moreover, while cost allocation has been resolved in terms of initial implementation of the program, it will certainly be reexamined in the future, after some experience has been gained under the rates set by D.87-12-039.

We agree with TURN that Hadson fails to recognize that D.87-12-039 is but one further step in a series of Commission actions that have vastly expanded opportunities for independent suppliers to market their gas to California end-users. It seems to us that entry into California under the Commission's program, while not yet perfected, is much preferable to no entry at all.

Edison. Edison contends that the Commission, in D.87-12-039, contravened "fundamental notions of fairness and due process" by modifying the stipulation signed by SoCal, PG&E, SDG&E, DRA (then PSD) and TURN in October 1986 ("Stipulation for Transition Period in Natural Gas Regulatory Procedure") to provide that SoCal's first reallocation filing will be no sooner that March 15, 1989. Edison argues that had it had notice that the Commission intended to make this modification, it would have vigorously protested, on the grounds that the rates which will be in effect from May 1, 1988 to June 30, 1989 will be totally outdated and inappropriate. Edison claims the Commission is bound by P.U. Code Section 1708 (mistakenly cited by Edison as 1705) to have hearings before modifying a decision (D.86-12-010 approved the stipulation in its entirety; thus "modification" of it now constitutes a modification of that decision as well). Edison finally argues that DRA and TURN, in advocating the change the Commission made, have violated the terms of the stipulation because they did not meet with the other signatories before seeking the modification.

Edison's arguments are completely misplaced on this issue. DRA's response puts it cogently:

> "The Stipulation simply does not provide for a SoCal cost allocation in the Spring of 1988. ... When this portion of the stipulation [relating to SoCal's cost allocation filing being due no later than March 15 of each year] is read in conjunction with the other provisions, the only logical conclusion is that the first annual cost allocation was intended to occur after the new rates set by the implementation decision took effect. Since the new rates don't take effect until May 1988, both TURN and DRA recommended that the Commission clarify that SoCal's first annual cost allocation occur in the spring of 1989."

DRA Response to Apps/Rhg at 7.

DRA goes on to cite specific paragraphs of the stipulation which support its and TURN's position. SoCal's and TURN's responses are basically in agreement with DRA.

We will modify the decision to clarify that the stipulation is not being modified, but merely being logically interpreted.

Edison secondly argues that by changing the cost allocation schedule, the UEG rates adopted in D.87-12-039 will be unlawful and unreasonable because they will be based not on the "best forecast available" as required by the stipulation, but on an outdated UEG sales forecast. As such, Edison claims these rates will overly burden electric ratepayers and are likely to result in SoCal's uncollecting margin from its UEG customers.

We agree with DRA that Edison's claim has no merit. DRA argues that the "best forecast available" language refers to the subsequent cost allocation proceedings and not the implementation decision establishing initial rates. DRA further points out that the adopted forecast, which Edison supported, was based on the best estimates then available, and is generally consistent with the adopted rates.

As DRA points out, the regulatory process is by its nature relatively slow. It can always be argued that the forecast used to adopt rates is a stale one. The fact that Edison has now generated a newer forecast does not, in the absence of a showing of evidentiary defects in the prior forecast, warrant a finding that the adopted rates are unreasonable. In addition, Edison's newer forecast is not part of the record and has not been subjected to cross examination.

Finally, we note that in the not-too-distant past, we set future rates based on the results of an historical test year. Such rates have never been found to be unlawful on that basis.

CMA. CMA alleges legal error concerning three aspects of the demand charge provisions contained in D.87-12-039. CMA first argues that customers who cease taking service before the implementation date must only be liable for existing demand charges rather than demand charges under the new program, in order that those customers have some bargaining leverage. We believe CMA's position reflects the intent of the decision, and we will clarify it accordingly.

CMA secondly argues that even if a customer has been buying gas under a rate schedule containing a demand charge and continues to buy gas as a default customer after the new rate design is implemented, the customer's use prior to the effective date of the new rate design should not be used to calculate the new demand charges. CMA states: "In short, CMA believes that the position expressed in D.87-07-044 and reiterated in D.87-12-039 is wrong." CMA App. at 4. PG&E supports CMA's position, but points out that such a modification would require a recalculation of rates and billing determinants. SoCal, DRA and TURN argue against this as being simply a rehash of arguments CMA has made numerous times before; they also point out that the demand charge structure was clearly set forth in D.86-12-009, and that as such, CMA had adequate notice of how it was to work.[2]

2 CMA also asserts, without argument or authority, that using a customer's past usage as a basis for calculating a future demand charge would constitute retroactive ratemaking. DRA correctly refutes this argument. While the method used to calculate the rate

(Footnote continues on next page)

We agree that we have seen and rejected CMA's argument on this point before, and we do so again.

CMA's third concern is over the one-year ratchet provision for demand charges. CMA admits to previously expressing its view and sponsoring testimony supporting its position that the one-year ratchett "will cause many default customers either to minimize their gas usage or to leave the system entirely." CMA App. at 6-7. This is apparently because of hardships which will be suffered by those default customers who experience significant swings in usage, and subsequently, very high or low bills for periods of up to a year. CMA recommends that we resolve this concern, as well as the two discussed above, by allowing all customers to establish "reasonable contract demands for purposes of administering demand charges." CMA App. at 7. Such could be established seasonally or annually, and ratcheting could be required "only if the customer's monthly usage consistently exceeds the contractually established demand quantity." Id. If the Commission does not want to adopt this approach, it should subject default customers to the new demand charges only to the extent that they take gas on or after the effective date of the new rate design.

We will deny CMA's contract demand proposal. This is a proper subject for utility/customer negotiations.

DGS. DGS, a state agency as well as a cogenerator, raises three issues concerning the adopted cogeneration rates.

DGS first argues that the adopted procurement rate for core cogenerators violates Section 454.4 because it does not insure that cogenerators receive a rate equal to or less than the rate

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(Footnote continued from previous page)

relies on historical usage, the rate is set prospectively to recover a portion of the utility's revenue requirement during the period the rates are in effect, and does not in any way attempt to recover utility costs incurred during a prior period.

charged the UEG class for gas used to generate electricity.[3]

The decision establishes a "true-up" mechanism which ensures that both core and noncore cogenerators pay a transmission rate which is no higher than the transmission rate paid by UEG customers. However, no such mechanism is adopted for procurement rates. Rather, the decision provides that core cogenerators will pay the same price for gas as UEG customers electing into the core portfolio, and noncore cogenerators (who qualify for noncore status like any other customer) will pay the noncore/UEG procurement price. DGS argues that core cogenerators will be denied the rate parity guaranteed by the statute if the utility from whom they buy gas elects noncore service, because they cannot buy gas at the lower noncore rate.

TURN's cursory response appears to agree with DGS. Due to a misreading of the decision, PG&E argues that DGS' argument is moot.

DRA argues, on the other hand, that the statute requires only the treatment afforded by the decision. If the Commission were to adopt DGS' position, it would in effect be telling SoCal that when Edison elects service from the noncore portfolio, SoCal must charge no more to its cogenerators than the noncore price. The decision itself implies that this is no longer possible now that the procurement aspect of gas service has been deregulated. DRA argues further that the fact that UEG customers have the option of electing in and out of the core does not mean that the Commission must create this same flexibility for all cogen customers, regardless of their ability to qualify for noncore status. The decision has allowed a parity rate for parity service; i.e., those UEG customers wanting the price and supply security of

3 Section 454.4 provides, in relevant part:

"The Commission shall establish rates for gas which is utilized in cogeneration technology projects not higher than the rates established for gas utilized as a fuel by an electric plant in the generation of electricity...."

core election will opt for core procurement service at the same procurement rate paid by core cogenerators.

We affirm the approach we adopted in D.87-12-039. This approach assumes that the statute allows us the flexibility to take into account the distinction we have established between core and noncore customers, and the way that distinction translates into procurement options and accompanying procurement rates. In our view, it is not relevant that many if not most cogenerators will be unable to buy gas from the gas utility at as low a price as their UEG utility can, due to the fact that "core" cogenerators cannot become noncore customers for gas procurement. What is important is that they be given the same procurement prices as core UEG customers if they are core cogenerators, and the same procurement prices as noncore UEGs if they are noncore cogenerators.

We reject DGS' view that the statute does not allow consideration of the core-noncore distinction, and that no matter what we do in other areas of gas regulation, we are locked into offering to <u>all</u> cogenerators the lowest rate that is available to a UEG customer when buying gas from a gas utility. We do not believe that the Legislature intended to place that restriction on our regulatory authority.[4]

DGS secondly argues that Section 454.4 requires specification by the UEG utility of the percentage of gas purchased from core and noncore portfolios and delivered via self-procurement, early enough to allow cogenerators to select the same

4 DGS makes the subsidiary argument that the Commission also violates Section 454.4 by equating UEG core usage with the rate used by UEG customers to generate electricity, because UEG core usage only involves the use of igniter fuel -- which doesn't generate electricity but only lights pilot lights. DRA and SoCal both challenge what they consider a narrow definition of igniter fuel. They argue that without igniter fuel, there is no generation of electricity; thus charging both core cogenerators and UEG customers the procurement rate for core volumes <u>is</u> rate parity, regardless of what point in the generation process the gas is being used. We agree with DRA and SoCal.

core election will opt for core service at the same rate paid by core cogenerators.

We affirm the approach we adopted in D.87-12-039. This approach assumes that the statute allows us the flexibility to take into account the distinction we have established between core and noncore customers, and the way that distinction translates into procurement options and accompanying procurement rates. In our view, it is not relevant that many if not most cogenerators will be unable to buy gas from the gas utility at as low a price as their UEG utility can, due to the fact that "core" cogenerators cannot become core-elect or noncore customers. What is important is that they be given the same procurement prices as core UEG customers if they are core cogenerators, and the same prices as noncore UEGs if they are noncore cogenerators. Along with this, core cogenerators are assured the same quality and security of service as is any other core customer.

We reject DGS' view that the statute does not allow consideration of the core-noncore distinction, and that no matter what we do in other areas of gas regulation, we are locked into offering to <u>all</u> cogenerators the lowest rate that is available to a UEG customer when buying gas from a gas utility. We do not believe that the inequitable result this leads to, i.e., that a core cogenerator choosing the non-core price for gas will get better service than any other noncore customer, would be countenanced by the Legislature.[4]

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4 DGS makes the subsidiary argument that the Commission also violates Section 454.4 by equating UEG core usage with the rate used by UEG customers to generate electricity, because UEG core usage only involves the use of igniter fuel -- which doesn't generate electricity but only lights pilot lights. DRA and SoCal both challenge what they consider a narrow definition of igniter fuel. They argue that without igniter fuel, there is no generation of electricity; thus charging both core cogenerators and UEG customers the procurement rate for core volumes <u>is</u> rate parity, regardless of what point in the generation process the gas is being used. We agree with DRA and SoCal.

DGS secondly argues that Section 454.4 requires specification by the UEG utility of the percentage of gas purchased from core and noncore portfolios and delivered via self-procurement, early enough to allow cogenerators to select the same option. Otherwise, DGS argues, cogenerators have no opportunity to obtain the parity rates mandated by the statute. DGS also claims that the average self-procurement price should be disclosed, to permit parity rates and to avoid "negative arbitrage" in avoided cost/purchased gas cost prices. DGS argues that failure to require such notice from the utilities is unlawful not only because of the Section 454.4 problem, but because the Commission has failed to consider the anticompetitive aspects of allowing the utilities to elect procurement options "in secret," which is required by NCPA, supra.

DRA favors the UEG notice, arguing that unless noncore cogenerators are given some advance notice of the total UEG procurement package, they may well not be able to match the UEG cost of gas. DRA recommends that at a minimum, notice should be given at the time that UEG customers change their procurement options. Rather than require lengthy advance notice, which would not allow UEG customers to respond quickly to changing market conditions, perhaps the Commission could build a lag into the avoided gas costs used to set QF payments. But DRA does not advocate deciding this question now; rather, there is no evidence that a short lag will hurt cogeneration customers, especially if they follow a least cost purchasing strategy.

We will adopt DRA's recommendation for UEG notice. We will modify the decision to require notice to be given to cogenerators by the UEG utility, immediately after it determines its procurement percentages. Such notice should include the average self-procurement price.

DGS finally argues that the gas utilities' expressed intention of treating cogeneration facilities with standby boilers as two customers (presumably because such customers have two gas meters) for purposes of customer and demand charges will constitute the imposition of unjust, unreasonable and discriminatory rates.

option. Otherwise, DGS argues, cogenerators have no opportunity to obtain the parity rates mandated by the statute. DGS also claims that the average self-procurement price should be disclosed, to permit parity rates and to avoid "negative arbitrage" in avoided cost/purchased gas cost prices. DGS argues that failure to require such notice from the utilities is unlawful not only because of the Section 454.4 problem, but because the Commission has failed to consider the anticompetitive aspects of allowing the utilities to elect procurement options "in secret," which is required by NCPA, supra.

DRA favors the UEG notice, arguing that unless noncore cogenerators are given some advance notice of the total UEG procurement package, they may well not be able to match the UEG cost of gas. DRA recommends that at a minimum, notice should be given at the time that UEG customers change their procurement options. Rather than require lengthy advance notice, which would not allow UEG customers to respond quickly to changing market conditions, perhaps the Commission could build a lag into the avoided gas costs used to set QF payments. But DRA does not advocate deciding this question now; rather, there is no evidence that a short lag will hurt cogeneration customers, especially if they follow a least cost purchasing strategy.

We will adopt DRA's recommendation for UEG notice. We will modify the decision to require notice to be given to cogenerators by the UEG utility, immediately after it determines its procurement percentages. Such notice should include the average self-procurement price.

DGS finally argues that the gas utilities' expressed intention of treating cogeneration facilities with standby boilers as two customers (presumably because such customers have two gas meters) for purposes of customer and demand charges will constitute the imposition of unjust, unreasonable and discriminatory rates. This is because "[i]n general (except for supplemental firing in excess of cogeneration production), only one use of the gas would ever occur at any one time." DGS App. at 9.

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PG&E and DRA dispute this charge. PG&E argues that cogeneration facilities with separately metered standby boilers involve two sets of customer-related facilities and services, thus two charges are appropriate. DRA appears to agree, arguing that the Commission's adopted rate design, based on a customer's assignable system cost responsibility on a per-meter basis, cannot assess system effects of multiple gas uses at a single location.

SoCal and TURN, however, believe that DGS' position has merit in those cases where the standby boiler system only operates to the extent that the cogeneration system is not operating.

We will adopt the SoCal/TURN position as the more equitable one. We will require the gas utilities to treat cogeneration facilities with standby boilers as one customer for purposes of assessing customer and demand charges, providing the cogeneration customer has signed an affidavit to the effect that its boiler system only operates when the cogeneration system is not operating.

IT IS ORDERED that Decision (D.) 87-12-039 is modified as follows:

1. The discussion entitled "Allocation Factors" beginning on page 8 is modified to read:

> "D.86-12-009 adopted allocation factors to divide nongas costs among the core, noncore, and wholesale markets. We explicitly chose relatively 'flat' factors which tend to spread these costs more evenly over all markets. These factors recognize that the current system was built to serve all customer classes, and that all users should contribute to paying for the current excess capacity in the system.
>
> As a general proposition, we concluded that all present customers, regardless of the services they choose, receive substantial benefit from the fact that a local distribution company has developed to the extent it has today. The utilities'

PG&E and DRA dispute this charge. PG&E argues that cogeneration facilities with separately metered standby boilers involve two sets of customer-related facilities and services, thus two charges are appropriate. DRA appears to agree, arguing that the Commission's adopted rate design, based on a customer's assignable system cost responsibility on a per-meter basis, cannot assess system effects of multiple gas uses at a single location.

SoCal and TURN, however, believe that DGS' position has merit in those cases where the standby boiler system only operates to the extent that the cogeneration system is not operating.

We will adopt the SoCal/TURN position as the more equitable one. We will require the gas utilities to treat cogeneration facilities with standby boilers as one customer for purposes of assessing customer and demand charges, providing the cogeneration customer has signed an affidavit to the effect that its boiler system only operates when the cogeneration system is not operating.

SoCal's Second Petition for Modification. On February 16, 1988, SoCal filed a second petition for modification of D. 86-12-009 and D. 87-12-039. SoCal asks us to require that wholesale customers obtain gas for their core customers from the core portfolio of their serving utility. SoCal also requests that UEG customers be required to purchase their Tier I volumes from the core portfolio. SoCal would be satisfied if these requirements were instituted on a temporary basis, pending the outcome of further hearings to determine if they should be made permanent.

SoCal asserts that, absent the imposition of these requirements, there will be a significant negative impact on SoCal's remaining core customers, without any offsetting benefits for wholesale and UEG customers. SoCal notes that wholesale core and Tier I UEG requirements, in an average year, approach 300 MMcfd. The addition of this load to the core portfolio would allow SoCal to include additional volumes of discretionary purchases in the core portfolio. SoCal asserts that these purchases would likely be at prices below the pre-existing core WACOG, and thus would reduce the core WACOG, to the benefit of all core customers.

structural and contractual relationships developed the way they did because the utilities procured gas for all customers. Moreover, today's low priority customers are still deriving benefits from the system, even though these benefits may exceed their present needs. It logically follows that all customers should continue to pay the unavoidable costs still being incurred as a result of the evolution of the utility structure, at least during the transition to reduction of excess capacity and configuration of the industry such that all customers can choose just what level of service they desire and be allocated costs accordingly.

"We concluded that "unavoidable 'common costs' associated with the transition to a more competitive market and not directly assignable to any particular customer class" should be spread equitably to both procurement and transmission-only customers. D.86-12-010 at 96. One of the classes of fixed costs to be treated in this way was fixed pipeline demand costs, which were incurred to bring gas into the system to provide basic service and peak reliability. We note, in addition to the above, that current transmission-only customers may still experience direct benefits from the above classes of costs. For example, should their independently-procured gas supply become unavailable, they can return to the utility for gas.

"We have been asked on several occasions since D.86-12-009 and D.86-10-010 were issued to revisit our allocation factors, and in both D.87-03-044 and D.87-05-046 we have firmly refused to do so. For the reasons we have set forth above, we reiterate today our intention not to revisit this issue until, as stated in our December 1986 decisions, such time as the present excess capacity is reduced."

2. The following new paragraph is inserted after the last full paragraph on page 103:

"We will, however, require UEG customers to notify their cogeneration customers, immediately after they have determined their

SoCal also notes that with a larger core portfolio, if it purchased additional supplies from El Paso and Transwestern, the per unit cost of gas from these pipelines would fall, and SoCal's exposure to take-or-pay costs passed through by the pipelines would likely decline. SoCal says that it is unclear whether take-or-pay costs accrued and billed after May 1, 1988, will be spread equally among all utility customers, or levied on just core customers; thus, increased take-or-pay costs could fall on just core customers. Finally, SoCal believes that as a practical matter it retains the obligation to serve wholesale core and UEG Tier I load. Thus, even if wholesale and UEG customers have procurement flexibility for this load, SoCal plans to incur additional costs in order to "backstop" these loads. SoCal submits that these extra costs can be avoided by requiring core procurement for these loads.

SoCal sees no positive benefits from allowing wholesale and UEG customers procurement flexibility for these loads, which SoCal points out are fundamentally "core" in nature -- i.e. there are no feasible alternatives to using gas. SoCal has provided the utility/public service function of procuring gas for these loads for many years, and sees no evidence that wholesale customers or the electric utilities would do a better job at that task. In addition, SoCal argues that such a shift in responsibilities would not produce any more competition than currently exists in California's restructured gas industry.

We have considered SoCal's request carefully, and have found nothing more in it than a very late attempt to stem a tide that is already running at full flood. First, implicit in SoCal's request is an assumption that its wholesale and electric utility customers might not recognize their own new public service responsibilities. We disagree strongly with SoCal's assertion that the change in SoCal's obligation to serve which accompanies our new program is merely a change "in theory", with little practical import. In fact, the wholesale customers and the electric utilities will now have important new public service responsibilities in their purchases of gas for "core" needs. We think that SoCal should recognize that SDG&E and Southern procurement packages, of the percentages of core, noncore, and self-procurement gas which they have included in the package. Each time the package changes, the UEG customer should provide new notice. This notice should include the average self-procurement price. This mechanism will assist noncore cogenerators in matching the UEG cost of gas."

3. The following paragraphs are inserted after the first full paragraph on page 104:

"On another subject, the California Department of General Services (the State) has raised the problem of the gas utilities' apparent intention to treat a cogeneration facility with a standby boiler as two customers for the purposes of assessing separate customer and demand charges. The State argues that this treatment ignores the use diversity between the two facilities; that the operation of the two facilities is inversely correlated, with only one use of the gas system occuring at any one time (with the exception of supplemental firing in excess of cogeneration production)."

"We agree with the State that the more equitable approach to this situation is to treat cogeneration facilities with standby boilers as one customer for purposes of assessing customer and demand charges, providing the cogeneration customer has signed an affidavit to the effect that its boiler system only operates when the cogeneration system is not operating."

4. Section I at the top of page 110 is modified as follows:

"D.86-12-009 was clear in providing that the noncore default customers would be obligated for demand charges for a one year period. The remaining issue is whether customers taking no gas on the implementation date should also incur demand charges for a one-year period based on historical usage. As a matter of policy, we believe that it is fair to excuse customers not taking gas on the implementation date from demand charges based on historical usage if: 1) those customers fall under a rate schedule which

California Edison, and the municipal utilities, are fully as accountable for the efficient discharge of their public service responsibilities as is SoCal. SDG&E and SCE must justify to this Commission the reasonableness of their gas purchases, including the purchases of independent supplies to meet core loads. We doubt strongly, for example, that SDG&E is ready at this time to rely on spot gas, or even on its own procurement of longer-term supplies, to meet more than a small portion of the requirements of its core customers. This is especially true given the fact that our hearings on the unbundling of storage are still underway; the Commission has issued no decision yet on SDG&E's request for independent access to a portion of SoCal's storage capacity. In addition, the FERC has yet to take the necessary steps which might allow SDG&E access to firm interstate pipeline capacity. And the recent gas curtailments in southern California should provide ample evidence of the perils of relying on short-term gas supplies. We are certainly concerned that SDG&E and SCE purchase firm, reliable supplies to meet those needs for which there is no alternative to the use of gas, and we will scrutinize the actions which they take toward that goal. We will also review carefully whether SoCal has purchased excess core supplies to "backstop" loads that it is no longer obligated to supply, and will not hesitate to refuse to recognize such excess costs in rates.

Clearly, the SoCal core portfolio is a logical and convenient source of dedicated, reliable gas supplies. Especially in the near term, SDG&E and SCE may very well purchase most if not all of their "core" requirements from the SoCal core portfolio. Yet SoCal's core portfolio may not be the <u>only</u> source of reliable supplies for these loads, and we decline SoCal's request to make it the only source by regulatory fiat. We disagree with SoCal's assertion that its request will not decrease competition: SoCal's proposal would preclude suppliers other than SoCal from competing to provide firm gas supplies to SDG&E, Long Beach, and the electric utilities. Rather than seeking a regulatory shelter from competition, we would prefer to see SoCal devote its energy to assembling a core portfolio that can compete with other gas

> does not currently contain a demand charge or 2) those customers have not used gas for the year prior to the implementation date. Customers who do not take gas on *or after* the implementation date of the new rate design will not be subject to the higher demand charges under that rate design, but will only be subject to demand charges under applicable rate schedules in effect prior to the implementation date."

5. The second to last sentence in the first full paragraph on page 116 is modified to read:

> "Therefore, consistent with logical interpretation of the stipulation, we will provide that the first annual reallocation filing that we will allow will be PG&E's September 15, 1988, filing."

6. The following new Findings are added to precede Finding 1 on page 118:

i. "We concluded in our December 1986 decisions that a) all present customers, regardless of the services they choose, receive substantial benefit from the structure and function of the local distribution company; and b) these benefits extend to low priority customers, even though they may exceed those customers' present needs or may constitute potential future benefits."

ii. "We further concluded that because of these benefits, all customers should continue to pay the unavoidable costs still being incurred as a result of the evolution of the local distribution company structure to its present state of excess capacity, at least until the excess capacity has been reduced and the industry re-formed such that customers may choose and will be allocated the costs of services to match their exact needs."

iii. "We finally concluded that unavoidable 'common costs' associated with this transition and not readily assignable to any given customer class, e.g., pipeline demand charges, should be spread suppliers for these core loads. Perhaps SoCal should begin by reassessing its "must take" obligations which it says so limit its flexibility in purchasing core supplies.

SoCal argues that the smaller the core portfolio, the higher the average price charged by its pipeline suppliers and the greater the take-or-pay liabilities which the pipelines will seek to pass through to the California utilities. This is not a new problem; it is a concern which we have faced since wellhead deregulation and the increasing availability of transportation allowed the utilities and their customers dramatically increased flexibility in procuring gas supplies. In the past, the utilities, including SoCal, have rationalized lower takes of pipeline sales gas because the resulting take-or-pay liabilities were more than offset by the savings in gas costs. Now SoCal apparently feels that this is not true for firm supplies, asserting that "there is no evidence that [the wholesale and UEG] customers can obtain supplies as firm and stable in price as SoCalGas' core portfolio gas at a price much, if any, lower than SoCalGas' core portfolio WACOG." However, if SoCal's core portfolio, <u>including</u> pipeline sales gas, is indeed the most economical firm supply available, then SoCal should be confident that the wholesale and UEG customers <u>will</u> elect into SoCal's core portfolio.[5]

For the above reasons, we will deny SoCal's proposed modification to D. 86-12-009 and D. 87-12-039.

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5 SoCal states that core customers alone may have to bear take-or-pay liabilities accrued and billed after the May 1, 1988, implementation date. We find no support for that statement in either D. 86-12-009 or D. 87-12-039. Our current policy, which we expect to continue after the implementation date, is to treat as transition costs all take-or-pay liabilities resulting from gas purchase contracts or arrangements which took effect before the division of the supply portfolio in D. 87-12-009 and 010. We have no reason to believe that California's pipeline suppliers will not continue to accrue liabilities under such contracts after May 1, 1988, nor can we forsee any reason to modify after that date our current policy for the allocation of transition costs. Transition costs are allocated to all customer classes on an equal cents per therm basis.

equitably to both procurement and transmission-only customers."

7. New Ordering Paragraph 8 is added to read:

"Initially, and each time UEG customers change their procurement packages, they shall immediately notify their cogeneration customers of the percentages of core, noncore, and self-procurement gas which they have included in the package. This notice should include the average self-procurement price."

8. New Ordering Paragraph 9 is added to read:

"The gas utilities shall treat cogeneration facilities with standby boilers as one customer for purposes of assessing customer and demand charges, providing the cogeneration customer has signed an affidavit to the effect that its boiler system only operates when the cogeneration system is not operating."

IT IS FURTHER ORDERED that the applications for rehearing of D.87-12-039 as modified herein are denied.

This order is effective today.

Dated MAR 0 9 1988 at San Francisco, California.

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

PG&E's Petition for Modification of D. 87-12-039. PG&E's petition raises four issues, only one of which we will resolve at this time.

PG&E also asks us to clarify our cogeneration rate design. PG&E cites language on page 102 of D. 87-12-039 which it says implies that the cogeneration class is to be "folded into" the commercial and industrial classes for rate design purposes. PG&E says that this is inconsistent with the decision's later adoption of SoCal's proposal to merge cogeneration and UEG customers into one UEG/Cogen class. PG&E is also unclear on the structure of the "otherwise applicable" transportation rate which will be the basis for one of the two bills calculated each month for cogeneration customers. PG&E appears to ask us to create a "noncore cogeneration transportation rate", set this rate equal to the average UEG rate, and use this rate as the "otherwise applicable" rate. This rate would have a structure similar to other industrial and UEG rates. Finally, PG&E says that under this interpretation the cogeneration shortfall will diminish, but not disappear; PG&E recommends that we establish a tracking account to accumulate the shortfall between cost reallocations.

No party fully supported PG&E's requested clarification. SoCal, for example, believes that PG&E's request is based upon a misunderstanding of what constitutes the cogenerators' "otherwise applicable" rate. SoCal states that the "otherwise applicable" rate is "the industrial or commercial transmission rate which would apply to the cogenerators' heating or process needs if he had no cogeneration equipment." There is no separate noncore cogeneration rate, as that rate has been merged into the rate of the combined UEG/Cogen class. There is in addition no need to clarify the structure of the "otherwise applicable" rate, as it is just the structure of the default tariff which would apply to the customer's heating or process usage in the absence of cogeneration. SoCal notes that it has proposed a purely volumetric cogeneration rate, to allow the rate to maintain absolute parity with fluctuations in the average UEG rate. Finally, SoCal feels that the decision accurately notes that there will be no "cogeneration shortfall" so long as the rate for the UEG/Cogen class is less than those for other industrial and commercial classes. The DRA concurs with SoCal.

We have reviewed this issue carefully, and have concluded that SoCal has accurately characterized the cogeneration rate structure which D. 87-12-039 established. PG&E fundamentally misunderstands what constitutes the "otherwise applicable" rate. In a nutshell, here is how cogeneration transportation rates will be designed and billed: for cost allocation and default rate calculation purposes, cogeneration throughput will be merged with UEG volumes into a single UEG/Cogen customer class. Then each month, the utility will calculate two bills for transmission service for each cogeneration customer: one applying the actual average transportation rate paid by UEG customers, lagged by 60 days; and one applying the industrial or commercial transportation rate which that customer would pay for heating or process needs if it had no cogeneration equipment (the "otherwise applicable" rate). The customer will pay the lower of the two bills. There is no "cogeneration shortfall" unless the "otherwise applicable" rate is less than the UEG rate. D. 87-12-039 needs no further clarification on this issue. PG&E must refile its tariff sheets to reflect accurately the cogeneration rate structure established in that order.

We do concur with PG&E that if a cogeneration shortfall does materialize, the utility should establish an account to track the shortfall so that it can be reallocated in the next cost allocation proceeding.

Hadson's Petition for Modification of D. 87-12-039. Hadson Gas Systems (Hadson) filed a Petition for Modification of D. 87-12-039 on February 22, 1988. In its Petition, Hadson seeks to expand the function of the priority charge previously adopted by the Commission to ration capacity on the utilities' systems. Briefly, Hadson seeks to use the priority charge to allocate interstate pipeline capacity by using the charge to allocate capacity shortages on either the intrastate or interstate pipeline systems.

We note at the outset that the precise operation of the priority charge mechanism has been deferred to the ongoing procurement hearings in I. 87-03-057. For that reason alone, we would decline to undertake such a dramatic expansion of the priority charge mechanism without the opportunity to obtain the views of other parties. However, careful consideration of the Hadson proposal reveals even more difficult barriers to its adoption.

First, the Federal Energy Regulatory Commission (FERC) is clearly entrusted with the jurisdiction to regulate the transportation of natural gas over interstate pipelines under the provisions of Section 1b of the Natural Gas Act (15 U.S.C. §717b). The FERC has imposed its own system for regulating the priority of gas shipments over interstate pipelines in the form of a "first come, first served" policy, adopted in the FERC's Order No. 436, (Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, 50 Fed. Reg. 42408 (October 18, 1985), FERC Regulations and Preambles ¶30,665 at 31,516.)

While Hadson blithely assumes that the California priority charge could be used to determine which customer is curtailed first in a shortage of interstate capacity (the customer paying the lowest California priority charge), such a system provides no assurance that the next shipper in the FERC's first come, first served queue will be next in line under the California priority charge system. We foresee substantial difficulty in coordinating the two priority systems. If, for instance, shippers exercised their federal priority rights to deliver gas to the interstate pipeline, yet were refused delivery in California because of the operation of the California priority charge, both the interstate pipeline and the utility would face a future obligation to deliver gas without any assurance as to when such delivery would be possible depending upon the demand for transportation and the priority charges paid by competing customers.

Hadson asserts that the key to making its proposal work is the adoption of reasonable balancing provisions. Yet under the example described above, a customer could quickly build up substantial balances of undelivered gas. We are not prepared to judge that either the interstate pipelines or the utilities are capable of managing such a balancing arrangement in the face of conflicting or incompatible state and federal pipeline priority systems. Nor are we inclined to precipitate a legal challenge to federal regulation of interstate pipeline capacity allocation through the use of our priority charge mechanism. Accordingly we will decline to adopt Hadson's suggestion.

IT IS ORDERED that Decision (D.) 87-12-039 is modified as follows:

1. The discussion entitled "Allocation Factors" beginning on page 8 is modified to read:

> "D.86-12-009 adopted allocation factors to divide nongas costs among the core, noncore, and wholesale markets. We explicitly chose relatively 'flat' factors which tend to spread these costs more evenly over all markets. These factors recognize that the current system was built to serve all customer classes, and that all users should contribute to paying for the current excess capacity in the system.
>
> As a general proposition, we concluded that all present customers, regardless of the services they choose, receive substantial benefit from the fact that a local distribution company has developed to the extent it has today. The utilities' structural and contractual relationships developed the way they did because the utilities procured gas for all customers. Moreover, today's low priority customers are still deriving benefits from the system, even though these benefits may exceed their present needs. It logically follows that all customers should continue to pay the unavoidable costs still being incurred as a result of the evolution of the utility structure, at least during the transition to reduction of excess capacity and configuration of the industry such that all customers can choose just what level of service they desire and be allocated costs accordingly.
>
> "We concluded that "unavoidable 'common costs' associated with the transition to a more competitive market and not directly assignable to any particular customer class" should be spread equitably to both procurement and transmission-only customers. D.86-12-010 at 96. One of the classes of fixed costs to be treated in this way was fixed pipeline demand costs, which were incurred to bring gas into the system to provide basic service and peak reliability. We note, in addition to the above, that current transmission-only customers may still

experience direct benefits from the above classes of costs. For example, should their independently-procured gas supply become unavailable, they can return to the utility for gas.

"We have been asked on several occasions since D.86-12-009 and D.86-10-010 were issued to revisit our allocation factors, and in both D.87-03-044 and D.87-05-046 we have firmly refused to do so. For the reasons we have set forth above, we reiterate today our intention not to revisit this issue until, as stated in our December 1986 decisions, such time as the present excess capacity is reduced."

2. The following new paragraph is inserted after the last full paragraph on page 103:

"We will, however, require UEG customers to notify their cogeneration customers, immediately after they have determined their procurement packages, of the percentages of core, noncore, and self-procurement gas which they have included in the package. Each time the package changes, the UEG customer should provide new notice. This notice should include the average self-procurement price. This mechanism will assist noncore cogenerators in matching the UEG cost of gas."

3. The following paragraphs are inserted after the first full paragraph on page 104:

"On another subject, the California Department of General Services (the State) has raised the problem of the gas utilities' apparent intention to treat a cogeneration facility with a standby boiler as two customers for the purposes of assessing separate customer and demand charges. The State argues that this treatment ignores the use diversity between the two facilities; that the operation of the two facilities is inversely correlated, with only one use of the gas system occuring at any one time (with the exception of supplemental firing in excess of cogeneration production)."

"We agree with the State that the more equitable approach to this situation is to treat cogeneration facilities with standby boilers as one customer for purposes of assessing customer and demand charges, providing the cogeneration customer has signed an affidavit to the effect that its boiler system only operates when the cogeneration system is not operating."

4. Section I at the top of page 110 is modified as follows:

"D.86-12-009 was clear in providing that the noncore default customers would be obligated for demand charges for a one year period. The remaining issue is whether customers taking no gas on the implementation date should also incur demand charges for a one-year period based on historical usage. As a matter of policy, we believe that it is fair to excuse customers not taking gas on the implementation date from demand charges based on historical usage if: 1) those customers fall under a rate schedule which does not currently contain a demand charge or 2) those customers have not used gas for the year prior to the implementation date. Customers who do not take gas on <u>or after</u> the implementation date of the new rate design will not be subject to the higher demand charges under that rate design, but will only be subject to demand charges under applicable rate schedules in effect prior to the implementation date."

5. The second to last sentence in the first full paragraph on page 116 is modified to read:

"Therefore, consistent with logical interpretation of the stipulation, we will provide that the first annual reallocation filing that we will allow will be PG&E's September 15, 1988, filing."

6. The following new Findings are added to precede Finding 1 on page 118:

i. "We concluded in our December 1986 decisions that a) all present customers, regardless of the services they choose, receive substantial benefit from the structure and function of the local distribution company; and b) these benefits extend to low priority customers, even though they may exceed those customers' present needs or may constitute potential future benefits."

ii. "We further concluded that because of these benefits, all customers should continue to pay the unavoidable costs still being incurred as a result of the evolution of the local distribution company structure to its present state of excess capacity, at least until the excess capacity has been reduced and the industry re-formed such that customers may choose and will be allocated the costs of services to match their exact needs."

iii. "We finally concluded that unavoidable 'common costs' associated with this transition and not readily assignable to any given customer class, e.g., pipeline demand charges, should be spread equitably to both procurement and transmission-only customers."

7. New Ordering Paragraph 8 is added to read:

"Initially, and each time UEG customers change their procurement packages, they shall immediately notify their cogeneration customers of the percentages of core, noncore, and self-procurement gas which they have included in the package. This notice should include the average self-procurement price."

8. New Ordering Paragraph 9 is added to read:

"The gas utilities shall treat cogeneration facilities with standby boilers as one customer for purposes of assessing customer and demand charges, providing the cogeneration customer has signed an affidavit to the effect that its boiler system only operates when the cogeneration system is not operating."

IT IS FURTHER ORDERED that the applications for rehearing of D.87-12-039 as modified herein are denied.

IT IS FURTHER ORDERED that SoCal Gas' second petition for modification of D. 87-12-039, PG&E's petition for modification on the issue of cogeneration rates, and Hadson's petition for modification are denied. PG&E shall file a revised default tariff for service to cogenerators which reflect the correct interpretation of D. 87-12-039.

This order is effective today.

Dated MAR 0 9 1988 at San Francisco, California.

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