Decision 88-03-008 March 9, 1988

ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Rulemaking Proceeding on the Commission's Own Motion to Revise Electric Utility Ratemaking Mechanisms in Response to Changing Conditions in the Electric Industry.	I.86-10-001 (Filed October 1, 1986)

INTERIM OPINION

In Decision (D.) 87-05-071, we determined that our review of proposed contracts for sales from California's largest electric utilities to individual customers at other than tariff rates would be aided by a set of guidelines for these special contracts. We decided that the most efficient way to develop the guidelines was through a workshop. To focus the workshop's discussions, we proposed several guidelines for the parties' consideration. However, we encouraged the parties to bring in their own proposals for guidelines, and we made clear that the purpose of the workshop was "to air various proposals for guidelines and to allow interested parties to comment on the advantages and disadvantages of the proposals." In D.87-05-071, we decided to focus our initial attention on the specific circumstances of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), San Diego Gas & Electric Company (SDG&E), and our proposed guidelines covered only those utilities.

The workshop on the guidelines was held on July 27 and 28, 1987. At the close of the workshop, the Administrative Law Judge (ALJ) determined that additional comments stating the positions of the parties on the various proposals were desirable, and on July 31, he issued a ruling inviting such comments to be filed by August 14.

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Some parties seemed confused about how adopting guidelines would affect our review of special contracts. PSD in its comments recommended that contracts that conformed with the guidelines should be filed by advice letter for minimal review by the Evaluation and Compliance Division. Further, PSD recommended that no approval be given for contracts that did not conform to the guidelines.

PG&E's comments also asked the Commission to clarify the status of a contract that meets the guidelines. In PG&E's opinion, such contracts should proceed through the Expedited Application Docket procedure, but should not be subject to a hearing and should receive approval by the Commission within 30 days after the workshop reviewing the agreement.

As we made clear in the May decision, these guidelines are not intended in any way to limit the utilities' ability to negotiate special contracts with their customers. The guidelines' sole purpose is to allow for a faster review than would otherwise occur. Contracts with terms that do not conform to the guidelines will not receive the quick review made possible by the guidelines, but such agreements may still be approved if the contract can be shown to be fair to other ratepayers. Thus our goal in developing the guidelines is not to specify the exact terms of the special contracts, but to develop a set of safeguards that should assure that contracts conforming to the guidelines meet certain key standards and do not disadvantage other ratepayers.

It is our current intention that all special contracts should be filed under the Expedited Application Docket (EAD). As we discuss later in this decision, the accelerated review provided by the EAD should include contracts for incremental sales, as well as contracts designed to avoid uneconomic bypass.

CORRECTION

THIS DOCUMENT HAS

BEEN REPHOTOGRAPHED

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LEGIBILITY

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The workshop on the guidelines was held on July 27 and 28, 1987. At the close of the workshop, the Administrative Law Judge (ALJ) determined that additional comments stating the positions of the parties on the various proposals were desirable, and on July 31, he issued a ruling inviting such comments to be filed by August 14.

Post-workshop comments were filed by the Commission's Public Staff Division (PSD), PG&E, Edison, SDG&E, the Natural Resources Defense Council (NRDC), a group of large industrial customers consisting of Anheuser-Busch Companies, Inc., General Motors Corporation, Nabisco Brands, Inc., Mobil Oil Corporation, New United Motor Manufacturing, Inc., Stauffer Chemical Company, and Union Carbide Corporation (Industrial Users), the State of California's Department of General Services (DGS), and Pacific Power and Light Company (Pacific Power). PG&E, Edison, SDG&E, NRDC, and the Cogeneration Service Bureau (CSB) also made written presentations at the workshop. On September 18, 1987, SDG&E also filed a response to certain comments of PSD.

The ALJ's proposed decision in this case was filed on December 8, 1987, and parties were allowed an opportunity to comment on the draft. Comments were received by PG&E, the Division of Ratepayer Advocates (the successor to PSD), Edison, SDG&E, NRDC, the California Energy Commission, DGS, the Industrial Users, Chevron U.S.A., and the Northern California Power Agency, which also submitted a Petition to Intervene.

In this decision we adopt a set of guidelines and discuss several related issues.

I. The Purpose of the Guidelines

In D.87-05-071, we described the development of guidelines as one of the most urgent tasks facing this proceeding. At the time, our concerns had been raised by utilities' allegations that several large customers were rapidly approaching their deadlines for deciding whether to build self-generation facilities. We had previously determined that we wanted to review all special contracts with potential bypassers, and we had set up the Expedited Application Docket (EAD) to provide for more rapid review of these contracts. The guidelines were viewed as an additional way to speed up the review of some of the special contracts.

Some parties seemed confused about how adopting guidelines would affect our review of special contracts. PSD in its comments recommended that contracts that conformed with the guidelines should be filed by advice letter for minimal review by the Evaluation and Compliance Division. Further, PSD recommended that no approval be given for contracts that did not conform to the guidelines.

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As we made clear in the May decision, these guidelines are not intended in any way to limit the utilities' ability to negotiate special contracts with their customers. The guidelines' sole purpose is to allow for a faster review than would otherwise occur. Contracts with terms that do not conform to the guidelines will not receive the quick review made possible by the guidelines, but such agreements may still be approved if the contract can be shown to be fair to other ratepayers. Thus our goal in developing the guidelines is not to specify the exact terms of the special contracts, but to develop a set of safeguards that should assure that contracts conforming to the guidelines meet certain key standards and do not disadvantage other ratepayers.

It is our current intention that all special contracts should be filed under the Expedited Application Docket (EAD). As we discuss later in this decision, the accelerated review provided by the EAD should include contracts for incremental sales, as well as contracts designed to avoid uneconomic bypass.

Under the EAD, a workshop is held shortly after the filing of the application. At the workshop, the assigned moderator determines whether any protests filed to the application require evidentiary hearings. The workshop is also an appropriate forum for the determination of whether a contract conforms with the guidelines. The utility's application should include a complete statement of how the contract meets the guidelines.

If there are no protests, and if the contract falls within the guidelines, it should normally be recommended for approval within 30 days of the workshop. However, we cannot say at this time that routine approval will always be granted to every contract conforming to the guidelines. The purpose of the guidelines is, as already stated, to speed our review. The purpose of our review of these contracts is to ensure that other ratepayers are not unduly disadvantaged by these contracts. The guidelines are designed so that if a contract conforms to the guidelines, we should be assured that other ratepayers will not be harmed, and we have tried to fashion guidelines with this purpose in mind. However, the field of special contracts is still new to both the Commission and the utilities. We are not yet convinced that the guidelines are adequate to screen out all contracts that may injure other ratepayers. Although we contemplate that all contracts conforming to the guidelines will be approved without hearings, we reluctantly reserve the right to examine unusual terms of unusual contracts in a hearing when such a review is needed to ensure that other ratepayers are not harmed. With time and experience, we fully expect that this reservation can be dropped, and that the guidelines may fully function as intended.

Contracts not conforming to the guidelines will be subject to the normal EAD procedure, and may go to hearing if a protest is made or if certain elements require further investigation.

If a contract that conforms to the guidelines is protested, the moderator will examine the basis of the protest to determine if hearings are needed.

The concern underlying PSD's recommendation that the Commission should not approve contracts deviating from the guidelines is misplaced, since the point of our review, whether or not the contract conforms to the guidelines, is to see that the interests of other ratepayers are protected. No useful purpose would be served by refusing to engage in such a review.

We hope in the future to be able to narrow and to eliminate our review of some contracts. After the elimination of the Electric Revenue Adjustment Mechanism (ERAM), for example, we may reach the stage when contracts for incremental sales will not need review. Ideally, we would be able to establish a system of incentives so that the utility's interests would never conflict with ratepayers. Experience may also teach us which terms of the contracts are likely to require review and which terms may be safely ignored or limited.

Although the guidelines are intended to allow the utilities flexibility in their negotiations, the utilities should recognize that the principles and the logic underlying the specific guidelines should be respected in contracts not conforming to the guidelines. Thus, although a particular contract may contain a floor term that varies from the mechanism specified in the guidelines, for example, it is nearly impossible to imagine that a contract that failed to recover the utilities' short-run costs of providing energy could be found reasonable.

II. Contracts for Incremental Sales

The initial focus for the guidelines was on impending special contracts with customers who were threatening imminent bypass of the utilities' systems. The regulatory policies we adopted in D.87-05-071, however, allowed for another type of contract at less than the tariff rate. We recognized that, with the elimination of ERAM and the existence of generating capacity well above target reserve margins, utilities had an opportunity to stimulate additional sales to some customers by offering a reduced rate for such incremental sales. By "incremental sales," we mean those additional sales that would not be made under existing tariff rates; the additional sales are made only because of the utility's ability to offer a discounted rate. In our earlier decision, we did not discuss the role of the guidelines with regard to these incremental sales.

The threshold issue is whether we intend to review special contracts for incremental sales. In setting up the Expedited Application Docket, we referred only to the anti-bypass type of special contract, and because of the EAD's specific requirements, a contract for incremental sales could not qualify for the accelerated procedure. To clarify this point, we do want to review special contracts for incremental sales, at least initially, and we will modify our Expedited Application Docket to allow for a faster review of these contracts.

Further, we believe that many, but not all, of the guidelines we adopt in this decision should also apply to special contracts for incremental sales. As we discuss each guideline, we will make clear whether and to what extent the guideline applies to the contracts for incremental sales, as well as the primary focus, the anti-bypass special contract.

III. The Proposed Guidelines

A. Floor Price

The parties reached an unusual level of agreement in recognizing the need for some sort of floor price guideline. The parties agreed that the floor price should ensure that the utility recovers all of the costs it incurs in serving the customer under the contract, and thus should avoid hidden subsidies from other ratepayers. In keeping with the advisory nature of the guidelines, we agree with PSD's characterization of the floor price appropriate to a guideline as "the lowest price possible that does not disadvantage other ratepayers in either the short or long run." Within this general definition, however, there is room for differences of opinion, and the parties differed considerably over the appropriate components of the floor price.

1. Energy Cost

The parties generally agreed that it was necessary for the floor price to cover all of the short-run costs of the fuel required to produce the electricity sold to the customer under the contract. Most parties felt that use of the Standard Offer Number 1 (SO#1) energy formula was an appropriate mechanism for the energy component of the floor price. This mechanism has been approved by the Commission for use in pricing purchases of power from independent power production facilities. Each utility adjusts its SO#1 energy price quarterly to reflect changes in the price of the marginal fuel. The parties also agree that this component of the floor price should float during the term of the contract, to reflect changing fuel markets.

We agree that SO#1 sets an appropriate energy component for the floor price. The mechanism has worked well and has gained widespread acceptance in the alternative generation field, and it is fortunate that it also fits the needs of this proceeding.

In a related recommendation, PSD has suggested that utilities should also book a credit to their Energy Cost Adjustment Clause (ECAC) accounts monthly at the appropriate ECAC rates for each kilowatt-hour sold under special contracts. This crediting would guarantee that other ratepayers would not bear any of the fuel costs associated with service under the special contracts. These credits would be separate from the floor price, although there should be a close relationship between the level of SO#1 and the ECAC rates.

Edison raised a related point in response to one of PSD's suggestions during the workshop. Edison agrees that the utility should also make full contributions to other appropriate balancing accounts, such as the Major Additions Adjustment Clause (MAAC) account, for special contract sales that are included in the sales forecast. We agree that such crediting to ECAC and other relevant balancing accounts is appropriate to protect the interests of other ratepayers.

The purpose of requiring these credits is to ensure that other customers do not indirectly or inadvertently subsidize the customers purchasing under special contracts. The credits should be designed to cover the increases that occur in the balancing accounts when consumption increases incrementally. Within 30 days of the effective date of this decision, PG&E, Edison, and SDG&E shall submit a list of such credits to affected balancing accounts and a description, including suggested tariff revisions, of how they propose to make such credits.

2. Transmission and Distribution Costs

Considerable disagreement arose on the question whether transmission and distribution (T&D) costs should be included as a component of the floor price.

One side of the argument urged that T&D costs are sunk costs that don't vary in the short run. Since the marginal T&D cost of serving a customer under a special contract is zero, no T&D component should be included in the floor price. However, if service to a specific customer requires T&D expenditures by the utility, then the contract rate for that customer should include a T&D component to keep other ratepayers economically indifferent.

The other side was articulated primarily by PSD. PSD argued that the Commission had never adopted a vintaged rate approach to T&D costs, under which newer customers would bear the cost of the new facilities built to serve them. Rather, the Commission's approach to T&D marginal costs viewed the costs as rental charges. When T&D costs are seen as rental charges, they are variable in the short term, and they should be included as a component of the floor price. PSD therefore suggests that the floor should include a T&D component, based on the T&D marginal costs adopted in each utility's last general rate case. PSD suggests that this component could be escalated and fixed at the commencement of the contract.

Both sides of this argument have logical virtues. In the context of anti-bypass special contracts, in particular, T&D costs are mostly neither incremental nor decremental: added or retained consumption from the anti-bypass special contracts does not cause the system to incur additional T&D costs, but neither does self-generation and the associated reduction in consumption result in any likely T&D savings. For the sake of consistency with our general approach to the determination of marginal costs for T&D, we will agree with PSD that the floor price should include a component reflecting the rental value of T&D facilities. The marginal T&D cost established in each utility's general rate case shall serve as the T&D component of the floor. This component may be fixed at the outset of the contract, based on the T&D marginal cost adopted in the utility's last general rate case, with appropriate escalation. The T&D component may be stepped up annually over the term of the contract, according to a predetermined formula, or it may be levelized over the term of the agreement, again using appropriate escalators. The contract may also use the actual T&D marginal costs established in the general rate cases decided during the term of the agreement.

We will make one exception to this general approach. Contracts for incremental sales may result in increased load that requires modification of the T&D system or acceleration of the installation of planned improvements. In these cases, the contract price should recover an appropriate measure of these site-specific increased costs.

3. Generation Costs

The arguments over whether generation costs should be included in the floor price echo those surrounding the T&D issue. One side of the argument notes that sunk generation costs do not vary in the short term, and the addition or deletion of an individual customer doesn't change these sunk costs one whit. The opposing argument is that a customer under a special contract is making use of the system's generation capacity and therefore should make some contribution to help meet the costs of the system's generation resources.

PSD argues that the generation costs component can be reflected by use of the Energy Reliability Index (ERI), which was developed in connection with purchases from independent power producers. The ERI varies to reflect the value of additional capacity to the system. When the ERI is 1.0, the value of additional capacity is equivalent to the value of an additional combustion turbine. As additional capacity becomes necessary to meet reserve margin requirements, the index rises and generation by independent power producers should be stimulated by higher capacity prices. The index approaches 0.0 to reflect increasingly lower needs for additional generation for purposes of system reliability.

PSD thinks that use of this index is appropriate for the floor price, because utilities plan for additional generating plants based on the demand patterns that are established today. If the price of power sold under special contracts is artificially low, greater than appropriate demand will result, and the need for additional generation will be accelerated. PSD believes that the ERI is useful in establishing accurate price signals for appropriate levels of consumption by special contracts customers.

Some of the parties agree that use of the ERI would be appropriate if the utility had any new resources on the planning horizon (which they say they do not) and if the ERI accurately reflected today's situation (which they say it doesn't). Edison apparently joins PSD in agreeing that an ERI-adjusted capacity component is appropriate for the floor price. PG&E believes that a generation component is needed only if the contract in question extends into a period when the Commission's OIR-2 process has identified a need for added capacity. In a similar vein, the Industrial Users recommend that the 5- to 10-year contracts contemplated in this proceeding should not contain a generation component, since capacity will not be needed in that time frame. Pacific Power opposes any general requirement to include the generation component, unless and until additional resources are required.

We are persuaded that some reflection of capacity costs is appropriate for the floor price. In theory, the floor should equal the utility's long-run marginal cost of capacity. However, our estimates of long-run marginal capacity costs are not yet very reliable. In addition, the relatively short term that we allow for special contracts conforming to the guidelines permits us to consider other measures of the capacity component of the floor price.

Edison suggests that the ERI-adjusted short-run generation capacity costs contained in SO#1 are a reasonable measure of the generation costs of serving customers under special contracts. The ERI provides a readily available sliding-scale mechanism that can serve as a reasonably accurate signal of the cost of the demand that all customers place on the system. Although SO#1 reflects only very short-term capacity costs, we believe that, in light of the relatively short limits we place on special contracts conforming to the guidelines, the SO#1 capacity component provides a sufficient indication of the changing need for additional capacity. We will adopt the ERI-adjusted capacity price of SO#1 as an appropriate generation component for the floor price.

In applications for approval of specific contracts, we will entertain the utilities' proposals on how this component may be escalated, fixed at the outset of the contract, or levelized.

We are concerned about some of the utilities' statements during the workshops that the ERI is out of date or so inaccurate that it is unreliable. If a utility feels that its current ERI needs adjustment or refinement, it should either petition for appropriate adjustments in A.84-04-044, et al., or petition for a modification of this decision to alert us of its concerns.

In a recent proposed decision in Application (A.) 82-04-044, the ALJ noted several problems with applying the ERI to PG&E's system, because of its high proposition of weather-dependent hydroelectric resources. Because of these problems, we will not require PG&E to apply the ERI adjustment to its SO #1 capacity prices to serve as a floor price. PG&E may employ the adjustment adopted by the Commission in the pending decision in A.82-04-044.

To avoid harming other ratepayers, this guideline should apply to both anti-bypass and incremental sales contracts.

B. Size Limits

The specific question addressed in this section is what size limits, if any, should be placed on the contracts that fall within the guidelines for special contracts. However, a related and more complicated question is whether special contracts should be limited to only the customers whose sales and revenues will no longer be subject to ERAM. The latter question will be addressed in a later section of this decision.

For purposes of the guidelines, Edison and PG&E recommended a 1000 kilowatt limitation. They have presented the results of studies showing that nearly all of the potential for bypass resides with customers with a demand of 1000 kW or greater. The 1000 kW limit also coincides with their recommendations for the definition of the large light and power (LL&P) class.

SDG&E favors no limit. Because of the higher level of its rates compared to the other utilities, SDG&E has identified a greater potential for bypass among customers in the 20-1000 kW range. Accordingly, if any limit is adopted, SDG&E recommends that its limit be set at 20 kW.

PSD is still awaiting full responses to its data requests on this issue. From the limited data available to it, PSD is concerned that drawing the line at 1000 kW may be ineffective in warding off future bypass. PSD notes that the data supplied by PG&E and Edison indicate that fully half of the identified bypass potential among customers above 1000 kW has already been realized; that is, about half of the potential bypassers have already left or committed to leave the system. On the other hand, PSD notes, the utilities appear to have little information on the bypass potential for customers in the 500-1000 kW range. PSD fears that the greatest future bypass potential lies in this class, and that the incentives developed in this proceeding should be aimed at this class if avoiding future bypass is the goal. Accordingly, PSD recommends a limit of 500 kW for PG&E and Edison and 20 kW for SDG&E.

The Industrial Users concur with the utilities' proposals and recommend limits of 1000 kW for PG&E and Edison and 20 kW for SDG&E. Pacific Power recommends a limit of 500 kW, but it appears that this recommendation applies to its system only.

For the limited purposes of the guidelines, we think that setting the size guideline to include only contracts with customers with 1000 kW or more of demand serves a useful purpose. The only question we are addressing here is identifying which contracts qualify for the accelerated review made possible by the guidelines. We have become convinced that many customers of this size can present a credible threat of bypass; indeed, as PSD has pointed out, many customers of this class have already committed to leave the system. Information on the bypass potential of smaller customers, however, is sparser, and we believe that it would be useful for us to hear a more detailed justification of the bypass threat. Since contracts with smaller customers will not initially qualify for the accelerated approval made possible by these guidelines, we view the size limitation of the guidelines as a way of staying informed of new technological and economic developments that may extend the feasibility of bypass to smaller customers. The number of special contracts with smaller customers brought for our approval is an important and reliable indication of such developments. If we become more certain of the bypass potential for smaller customers, we will lower the size limit for purposes of the guidelines. The different circumstances of the individual utilities may eventually lead to different size limitations.

For similar reasons, this guideline should apply to incremental sales in the following fashion: Only contracts for incremental sales to customers whose base demand is 1000 kW or more come within the guideline. However, for these customers the individual contract for incremental sales does not need to amount to 1000 kW to qualify for accelerated review. Again, we expect to modify this size limit as we gain more experience in this area.

C. Maximum Term

In our May decision, we proposed a maximum term for contracts conforming to the guidelines of three years. In part, this proposal reflected a lack of confidence in our ability to foresee the course of the events affecting the electric utility industry, and in part it was related to the current length of the general rate case cycle.

The utilities were united in stressing that a term of at least five years was the minimum needed for a special contract to be considered by a customer. Because of the two- to three-year lead time for development and construction of a self-generation unit, customers need to begin to explore their electricity options about three years before the power is needed, or three years before the expiration of the contract. If the term of the contract is only three years, the customer would be forced into a constant state of planning and would likely choose self-generation at the outset to avoid the inconvenience of perpetual planning.

Several parties urged five years as the minimum term, with a maximum term of 10 years. SDG&E, for example, asserted that the utility, as the seller under the contract, benefited from longer contract terms and greater stability of its customer base. Accordingly, it urged that contracts of over five years should be allowed under the guidelines if the price is indexed to fuel costs; even without such indexing, contracts of up to five years should be permitted. Edison thought that an option, presumably exercised by the utility, for an additional five years should be available at the end of the initial five-year term.

A further question had to do with whether the customer should begin to receive the reduced rate when the postponed self-generation facility would have begun operation or when the contract was executed. Most parties thought the term should begin when the phantom plant would have started operation.

For purposes of the guidelines, we believe that a maximum term of five years is appropriate for contracts designed to deter self-generation by a customer. We recognize that the proposed three-year term would have been unattractive to most potential bypassers. We are still concerned, however, about future volatility in the industry, and we think that short contracts are preferable at this time. Also, we agree with the parties who suggested that for purposes of the guidelines the rate concessions should begin when the phantom bypass facility would have begun operation, since the customer is no better nor worse off under the contract if this commencement date is used. Again, contracts with longer terms may be negotiated by the utility and approved by the Commission, but they will not be guaranteed the quick review that the guidelines are intended to make possible.

For contracts for incremental sales, lead time is not such an important consideration, and our concern about forecasting conditions in a volatile economy weigh heavier in our decision. We conclude that for purposes of the guidelines, contracts for incremental sales should be limited to three years from the commencement of sales under the contract.

The guidelines should include a further limitation that should apply to both types of special contracts. The term of a special contract conforming to the guidelines should not extend into any year when forecasts indicate that additional capacity will be needed to meet target reserve margins. The purpose of allowing special contracts is to take advantage of existing excess capacity. Considerable justification will be required to demonstrate the benefits of extending discounted rates into a period when increased demand creates a need for additional capacity.

D. Time Differentiation

Two concerns underlie our desire for time differentiation of the special contracts' price terms. First is the fact it costs the utilities more to produce electricity during peak hours than during off-peak hours, since they must turn to progressively less efficient generating units to meet higher levels of demand. Our concern here is that the contract price should at least cover the utilities' cost of producing the power sold under the special contracts. Second, higher demands at peak periods often drives the need for additional resources, since the reserve margin is primarily designed to assure that peak loads are reliably met. At present, additional resources are usually more expensive and environmentally troublesome than relying on existing resources. Excessive on-peak demand may thus affect the rates charged to all customers, since the cost of constructing or obtaining new resources is borne by all customers. Our concern here is that the price signals of the contract should discourage undue on-peak consumption and should encourage the customer to flatten its load as much as possible.

These desires are tempered by our recognition that self-generation units make most sense for the customers when the facilities are designed to run at a high load factor. Thus, the facilities against which the special contracts will compete have flat costs for the customer. Even though high on-peak rates are offset by low off-peak rates, and thus high load factor customers are basically indifferent, excessive time differentiation requirements for the special contracts may tilt the customer's decision toward bypassing the system.

PSD argued strongly for time differentiation requirements. PSD recommends that only contracts with time-of-use energy rates and on-peak demand charges should fall within the guidelines. These two charges will signal both the hourly running costs of the utility in producing the power and the long-run cost of adding capacity to meet on-peak demand, according to PSD.

The utilities generally concede the need for some time differentiation in the rates of contracts falling within the guidelines, but they plead for more flexibility than PSD's proposals allow. Edison, for example, lists a number of options for time differentiation. A pre-defined load profile which limits the availability of the special contract rate, combined with a rate design which mirrors the costs of self-generation and consists of high fixed charges and low variable charges, gives the customer a great incentive to conform to the load profile as closely as possible. In its general rate case, Edison has proposed a Marginal Cost Contract Rate, which adjusts the fixed charge to reward or punish a customer for an improvement or deterioration of summer on-peak load factor. Edison also has a Spot Pricing Amendment in an agreement with one of its customers that limits the availability of the discounted on-peak rate and ties the limit to the customer's mid- and off-peak usage, thus creating a load-flattening incentive.

In addition, the customer's load is fully interruptible to mitigate the customer's contribution to long-term capacity shortages. Edison suggests that a variety of mechanisms should be sufficient to meet the time differentiation requirement of the guidelines.

PG&E also recommends that the goals of the time differentiation requirement may be met by any of a variety of mechanisms. It lists time-differentiated energy rates, defined load shapes, on-peak demand charges, and percentage discounts from tariff rates as possibilities. PG&E also points out that many special contract customers will continue to take a portion of their load at regular tariff rates, which are time-differentiated, and thus will face time-of-day pricing for marginal consumption. The load shifting incentives on the margin for such customers is as strong as for customers on tariffed rates.

For purposes of the guidelines, we think it is important both to ensure that the special contract's price should cover the utility's hourly costs and that the customer should have some signal reflecting the long-term effect of peak usage on the system. For purposes of the guidelines, we think the first objective is met if the energy component of the floor price is time-differentiated. We have already determined the the energy component of the floor price guideline should be the SO#1 energy payment; since this mechanism is routinely divided into time-differentiated components, it is a simple matter to incorporate the time-differentiated rate as the floor.

We want to make clear that the time-differentiated floor is adopted only for purposes of the guideline and the accelerated treatment that the guidelines make possible. Contracts with undifferentiated floors or other terms may be shown to be fair to other ratepayers by the applicant utility.

We also believe that it is important to maintain some time-of-use incentives in the customer's actual payment above the floor price. However, we also want to allow the utilities sufficient flexibility to make the special contracts attractive for potential bypassers. For purposes of the guidelines, we believe that this concern is satisfied if the differential between the on- and off-peak contract rate for marginal consumption is roughly the same as the differential between on- and off-peak rates in the applicable TOU tariff. This requirement may be met in many ways. Obviously, this requirement is met when part of the customer's load is subject to both on- and off-peak tariff rates. A percentage discount from the tariff rate is also acceptable. A properly constructed load profile, combined with an appropriate rate structure under the contract may also meet this guideline.

Apart from the mechanisms listed above, it may be difficult to determine whether a contract's time differentiation provision is roughly equivalent to the applicable TOU schedule's differentials. For such contracts, the utility and our staff will have to exercise some judgment in applying this guideline. Our intention here is to provide the utility with great flexibility in developing the appropriate rate provisions while retaining an effective signal about long-term consumption patterns.

E. Future Flexibility

In D.87-05-071, we expressed our interest in proposals for integrating special contracts with the utility's long-run resource needs. These proposals suggested that, as part of the consideration for receiving rate reductions, the customer could agree to take actions, perhaps at the end of the contract term, that would complement the resource planning of the utility. We invited proponents of this future flexibility to present specific proposals that would accomplish these purposes.

NRDC came forward with two related proposals. The first proposal called for utilities, after negotiating a special contract with a customer, to present the customer with an option of taking a conservation payment and continuing to take service at tariffed rates. The conservation payment would be the present value equivalent of the rate concessions expected to occur over the term of the contract, so that the utility would be economically indifferent as to which choice the customer accepted. If the customer thought that it could use the payment to reduce electricity usage by improving efficiency so that its total electric bill would be less than under the special contract, it would select the conservation payment. Otherwise, it would choose the rate reduction. According to NRDC, such incentive payments are one way to reduce market barriers to efficiency improvements, particularly the tendency of businesses to expect very short payback periods for their investments.

NRDC's second proposal provides the enforcement mechanism for its first proposal, but the second proposal has broader applicability. Under NRDC's second proposal, all customers receiving either rate reductions under special contracts or conservation payments would agree, as a term of their contracts, to one of two conditions: Either they would place a portion of their current loads on interruptible schedules in proportion to the reduction in the customer's bill resulting from the rate concession (or the conservation payment), or they would agree to install, on the utility's request, the self-generation equipment that was the basis for the bypass threat that resulted in the special contract.

The second proposal is an attempt to see that any increased demand stimulated by special contracts does not enter into the utility's long-run resource plans. By either having a portion of the customer's load on interruptible status or requiring the customer to construct the threatened self-generation equipment, the utility can avoid planning for increased load for that particular customer; the demand created by those customers should be stable.

The utilities generally questioned or opposed NRDC's proposals. Edison, for example, listed five of its concerns about NRDC's proposal for efficiency improvement payments. First, Edison questions NRDC's assumption that decisions about efficiency improvements are irrational, that a program like NRDC's payment proposal is needed to overcome market barriers. Edison believes that its customers' decisions regarding conservation investments are rational. Second, Edison is concerned about the risk of overpayment that is inherent in the forecast that NRDC's proposal requires. Calculating the conservation payment requires a forecast of tariff rates for the term of the contract and may also require other projections, depending on the specific terms of the discount. Any forecasting inaccuracy would lead to over- or underpayments of the conservation payments. Third, a customer may be interested in the conservation payment only if it believes the forecast of tariff rates is in error; Edison seems to believe that customers may bet against the forecast rather than for their ability to improve efficiency. Fourth, the fact that Edison's retail rates exceed its short-run marginal costs already gives customers ample incentive to invest in conservation. Finally, Edison thinks the proposal is still vague in its details. For example, Edison asks, how will the disposition of the conservation payments be monitored? How will base (noninterruptible) amounts of demand be established?

Other utilities echo Edison's concerns and add more of their own. SDG&E believes that the proposals are not suited for these guidelines, which are intended to ease the review of special contracts. According to SDG&E, NRDC's proposals are neither simple nor easy to administer. Furthermore, SDG&E fears that the requirement of offering a conservation incentive payment will undermine negotiations with customers. For example, if the utility does an excellent job of negotiating with a customer, the special contract may effectively produce no discount from expected tariff rates. This lack of a discount would be made painfully clear when the utility presented its required alternative payment--a conservation payment of nothing. Either the customer would feel cheated by such negotiations or conservation advocates would accuse

SDG&E of squelching conservation, in SDG&E's opinion. PG&E adds its fear that some customers would take the payment with the intention of going out of business, or merely reducing operations, before the end of the contract. In either case, the customer would not be required to spend one dime on conservation, yet it would evade the enforcement mechanisms proposed by NRDC.

PSD finds some merit in NRDC's proposals, but believes that further consideration may be necessary. Pacific Power seconds this belief.

NRDC has identified several very important problems. How do we put conservation investment on the same economic footing as self-generation and special contracts? How can we prevent the increased demand resulting from special contracts from accelerating the need for new capacity additions? What happens to our conservation programs after the elimination of ERAM? How do we integrate conservation and load management into our new framework of regulation?

NRDC's conservation incentive payment proposal assumes the existence of market barriers that disadvantage efficiency improvements. We have no doubt that market barriers exist; overcoming market distortions has been one of the continuing goals of our conservation programs. We are somewhat surprised at NRDC's assessment that substantial market barriers are still pervasive among the customers qualifying for special contracts. These customers, after all, are large entities, and we would expect that a company angling for a competitive advantage would jump at any reasonable opportunity to improve energy efficiency and thus decrease costs. Even among these large entities, the customers qualifying for the anti-bypass type of special contract should be those who are the most sophisticated about energy matters, since to receive serious consideration from the utility they must be well along in planning the construction of a self-generation unit. We would think that such customers would have evaluated the economic benefits of conservation thoroughly before deciding to commit large amounts of money to a self-generation facility. Thus, we would expect that these large customers would not be subject to a lack of information, perhaps the most common barrier to conservation.

We understand NRDC's proposal be aimed primarily at another market barrier, the short pay-back period used by companies in deciding whether or not to make conservation investments. Consideration of this particular market barrier leads us to one concern we have about NRDC's proposal. One reason a company may use a short pay-back criterion is that other investments by the company may result in even shorter pay-backs or higher internal rates of return. In such cases, the conservation incentive payment proposed by NRDC is unlikely actually to be spent on or result in conservation improvements. The result would be that the customer receives the use of the conservation payment for the term of the contract--essentially an interest-free loan--in exchange for deferring the construction of the self-generation facility. This may be a desirable result, but NRDC did not frame its proposal in these terms.

NRDC's proposal to require all customers taking special contracts either to place a portion of their load on interruptible status or to construct the self-generation unit that was the basis for the contract is interesting but perhaps undeveloped. We have three concerns about this aspect of NRDC's proposal.

First, we are concerned that this requirement may not be closely related to the benefit the customer receives under the contract, and that these requirements may encourage more customers to bypass the system rather than accept special contracts. For the customer, the choice posed by this proposal is whether it is willing to yield some control over its future operating decisions in exchange for rate reductions over the term of the contract. We are concerned that the customer may give this loss of operating flexibility disproportionate weight in the customer's consideration of its choices, and will introduce an element into the decision that is essentially unrelated to the issues we are concerned with.

Second, the increase in rates that customer faces at the end of a special contract may in itself be sufficient to cause the customer to build the self-generation facility. If high rates led the customer to plan self-generation before the contract was entered into, the resumed threat of high rates at the end of the contract term should lead to a similar response.

Third, if the utility has the discretion to select which of the special contracts customers are required to construct the self-generation facility, this discretion could be seen as undermining the auction program we have set up for selecting independent generators to supply power when the utility needs additional capacity. NRDC's proposal would leave the utility open to charges of manipulating the need for QFs by reducing load growth by exercising its contractual right to require construction of self-generation facilities. Our concern is not so much with this result, which may be desirable under some circumstances, as with the awkward position utilities are placed in with regard to the QFs. A further concern is the risk of inefficiency; that is, the utility might require construction of a less efficient self-generation unit while a more efficient QF project withers.

Despite these concerns, we believe NRDC has identified an important problem and has proposed a novel solution to that problem. We think our objections can be overcome by modifying NRDC's proposal somewhat. We will adopt a variation of NRDC's proposal, and we think that this variation will address the same concerns as NRDC's idea.

Under this variation, conservation options would be presented as part of the negotiations between the utility and the customer seeking a special contract. In addition to discussions of a possible discount from tariff rates, the utility would present the customer with a menu of conservation options. At this point the customer has three general choices: The customer may reject all of the conservation options and complete negotiations of a contract based solely on rate reductions. Or the customer may select a number of conservation programs, up to a specified dollar limit for that customer, in which case the contract will include those conservation items but will call for sales at full tariff rates. Or the customer may select a mixture of conservation items and rate discounts up to a limit of total concessions established for that customer.

The limit of the utility's conservation expenditures is similar to the maximum conservation incentive payment proposed by NRDC. The cost to the utility of the conservation items plus the net present value of any discounts from tariff rates should not exceed the present value of the total discount from tariff rates that the utility and the customer would agree to in the absence of the conservation option.

To give a simple example of this idea, let us suppose that a customer has negotiated a preliminary agreement that would result in a discount of 10 mills from tariff rates. That discount has a present value, let us assume, of $100,000. The customer could reject the conservation items and retain the full 10 mill discount in the final contract. Or the customer could accept $100,000 of conservation items in the final contract and remain at tariff rates. Or the customer could select $50,000 of conservation items (half of the limit for this customer) and receive power at a 5 mill discount (half the negotiated reduction) for the term of the contract. The customer would also be free to select other proportions of conservation and discounts, provided the utility's cost of the conservation items and the net present value of any rate discount did not exceed the total present value of the negotiated discount.

The items in the menu would be developed in a workshop. The items should come from new or existing conservation programs that meet the societal test of cost-effectiveness. The societal test takes a somewhat broader perspective than the rate impact test we have applied to other conservation programs. Use of the societal test in these circumstances is appropriate for two reasons. First, the societal test is better suited for addressing the problem pointed out by NRDC: that companies impose a much shorter pay-back period on conservation investments than the utility does when it invests in new generation. Allowing the utility to offer conservation programs based on the societal test is a way of grafting the longer pay-back criterion used by the utility onto the private industry's shorter period. Second, a strict adherence to the rate impact test is not appropriate under present circumstances when the greatest effect on rates would come if the customer leaves the system. The slight effect on rates of the societal test is far preferable to the large potential effect on rates of the loss of such customers.

The source of the funds for the utility's offered items will initially be the existing authorized funds for any conservation programs included in both the menu and in the programs authorized in the general rate case. Once these authorized program amounts are exhausted, the utility should request necessary additional amounts by an advice letter filing.

The incentives under this variation are slightly different from those of NRDC's proposal. The utility will still have an incentive to maximize net revenues, but the way to receive the most revenue from an individual customer is to push the conservation programs: Rates to an individual customer are higher to the extent that the customer chooses items from the conservation menu. And the overall goals of this program--to retain customers on the system without locking in higher levels of demand--will be well served by this variation.

In addition, since the conservation items are part of the utility's conservation programs, we will have assurance that the expenditures are actually going to further conservation more directly than under NRDC's proposal. We also believe this approach encourages the utility to view and employ conservation as an effective tool in its efforts to retain customers on the system.

One obstacle that this variation shares with NRDC's proposal is that it requires a forecast of tariff rates for the classes of the special contracts' customers. We believe that the utilities may be in the best position to make these forecasts. The utility's own interest should act to make the forecast as unbiased as possible. If the rate forecast is too high, then the utility may end up granting larger discounts than necessary to special contract customers, thus reducing the utility's net revenues. If the forecast is too low, the utility may find itself in a bad position to prevent customers from leaving the system. In addition, the utility's incentive to prefer conservation programs to rate discounts would be limited if the forecast is too low, since a low forecast would also limit the dollar amount of the conservation programs that the utility may offer an individual customer.

IV. Related Proposals and Issues

In addition to the comments on the proposed guidelines, D.87-05-071 requested comments on two other issues.

A. Definition of the Less Restricted Class

In D.87-05-071, we declared our intention to eliminate the Electric Revenue Adjustment Mechanism (ERAM) and the attrition rate adjustment (ARA) for the large light and power (LL&P) class. We also offered a tentative definition of the LL&P class, but we requested the utilities and others to offer more specific definitions of the class.

Partly in response to those proposed definitions, we believe that it is more accurate to refer to the customers who will not be covered by ERAM or the ARA as the less restricted class. This class is less restricted than other classes in two senses. First, the class is intended to include most of the customers who are not restricted to reliance solely on the utility for electricity and who have reasonably feasible options for self-generation. Second, the customers in this class are not restricted to the rates set out in existing tariffs; they have the possibility of negotiating a special contract or of choosing one of the rate options we discuss later in this decision. This term will also create less confusion if the class is expanded to include smaller customers.

1. The Function of the Definition

Before we discuss the precise definition, we should explain the significance of the class. As is obvious from the origins of the class, we intend that the rates for this class will not be altered between general rate cases to reflect varying sales levels, and rates for this class will not be adjusted for inflationary cost increases, financial attrition, or rate base attrition during the general rate case cycle.

A further question is whether special contracts will be available only to members of this class. Contracts for incremental sales within the class will benefit the utility by increasing revenues not subject to ERAM. Contracts for incremental sales to customers subject to ERAM benefit customers covered by ERAM by increasing ERAM revenues, which should help lower ERAM rates. Because of these benefits, utilities may enter into contracts for incremental sales with customers in the less restricted class and with customers covered by ERAM. Both the utility and the Commission staff assigned to review these contracts should ensure that these contracts do not violate the antidiscrimination standards of Public Utilities Code Section 453.

Anti-bypass special contracts present a more difficult question. This question brings into focus the two, sometimes inconsistent, goals of this proceeding--avoiding bypass and moving toward a more incentive-based regulation. If avoiding bypass is the primary goal, then special contracts should be allowed outside the less restricted class. Under this approach, if the utility's investigation and our review demonstrate that there is a real threat of bypass by a customer, then we should permit efforts to keep the customer on the system, no matter how small the customer is. Revenue losses resulting from special contracts with customers in classes covered by ERAM would be made up by other ERAM customers. On the other hand, if our main concern is minimizing the need for supervisory regulation of these contracts, then special contracts should be limited to the less restricted class, where incentives ensure that only customers with a real potential to bypass the system get the rate breaks and that the utility will negotiate to receive the maximum revenue from the customer.

The establishment of an incentive-based system is an important long-term goal of this proceeding. However, we will permit special contracts outside the less restricted class for a limited purpose. Special contracts can serve as a useful tool for alerting the Commission when technological and economic developments expand the potential for bypass to smaller customers. If the Commission begins to see many requests for special contracts with customers within the classes covered by ERAM, that should be signal that we should consider expanding the less restricted class.

2. <u>The Definition of the Less Restricted Class</u>

Ideally, we would define this class to include all potential bypassers, so that the problems discussed in the preceding section would not arise. However, the utilities have proposed limiting the less restricted class to customers over 1000 kW, even though they acknowledge that smaller potential bypassers already exist.

This issue raises concerns that expose once again the two, sometimes conflicting, goals of this proceeding. If our primary concern were prevention of bypass, then the less restricted class should be coextensive with the potential for bypass; this potential seems to extend to the 500 kW level for PG&E and Edison and to the 20 kW level for SDG&E. But a competing concern of reforming our system of regulating electric utilities would call for a more gradual approach, so that the new incentives could be introduced with a minimum of disruption to the utilities and their customers. A more moderate approach would be to begin with the less restricted class consisting of customers with demand of 1000 kW or more and to expand the less restricted class gradually as we gain more experience with the revised system of regulation.

The utilities make several arguments for the higher limits to the less restricted class. First, nearly all of the identified potential for bypass for PG&E and Edison is with the larger customers; for SDG&E with its higher level of rates, the potential extends to much smaller customers. Second, the smaller customer group included in the higher limit allows for ease of administration; it is easier to identify potential bypassers and to negotiate with the smaller class. Third, smaller, but significant, revenues are associated with the more narrowly defined class, so that any unanticipated increases in risk would have less effect on the utilities' financial health.

On the other hand, PSD points out that about half of the potential bypass customers of 1000 kW or more have already committed to leave the system, and there is considerable logic in expanding the class now to include potential future bypassers. In addition, a gradual expansion of the less restricted class would require a new forecast for each expansion. Repeated revisions of the forecast would be time-consuming and could undermine the incentives that we want to shape the utilities' behavior. Further, the additional administrative burden should be much less than the utilities fear if they have correctly determined that the current potential for bypass in the 500-1000 kW range is limited to a handful of customers.

For the present time we will accept the utilities' proposed definitions of the less restricted class as being limited to customers with demands of 1000 kW or greater. However, once we are persuaded that our incentive system can operate without great disruption, we will act to enlarge the class to include customers with demands as low as 500 kW for PG&E and Edison and perhaps as low as 20 kW for SDG&E. Accordingly, the utilities should begin considering how to develop forecasts of sales and revenues for these enlarged classes to supplement the forecasts for customers of 1000 kW or more that is now underway. We will focus initially on the latter forecasts, but we want to have the details of the forecasts for the enlarged class worked out so that we may act quickly to redefine the less restricted class.

B. Rate Options

In D.87-05-071, we found that rate options are a way of providing customers with choices that could keep some customers on the utility's system, and we offered the parties the opportunity to comment on "whether applications for rate options should be considered individually or in a consolidated proceeding."

Rate options refer to new tariffed rate choices that are designed to meet the needs of a group of customers. Since our current customer classes are fairly broadly defined, it may be possible to keep some customers on the system by altering the way in which they pay for service. The customer could voluntarily choose the option that best fit the characteristics of its need for service. Ideally, the rate options would recover over a reasonable time period the same amount of revenue from the customer class as current rates.

We asked the comments to address the specific question. "In what proceeding should rate options be considered?" We tentatively suggested in D.87-05-071 that proposals for rate options should be considered in each utility's ECAC proceeding, but that experimental or very new proposals should be examined in this investigation. A further question was whether the rate options should be reviewed individually, as they are filed, or consolidated to allow for common assumptions and consistent treatment.

The parties vary in their preferred approaches to examining rate options. PG&E has presented some rate option proposals in its ECAC case, but it urges the Commission not to foreclose consideration of proposals outside the ECAC and general rate cases. Edison would prefer to have its proposals heard in connection with its attrition filing, rather than its ECAC case. Edison does not think that the present proceeding is a proper forum for consideration of specific rate option proposals. SDG&E has filed some proposals as a separate application (although we note that this application has been consolidated with SDG&E's ECAC proceeding since the comments were filed). PSD urges the Commission to keep its reviewing options open and cautions against overloading the ECAC cases. CEC notes that the marketing data to support narrowly defined customer classes has not yet been developed, and it points out that increasingly narrow classes will make forecasting difficult. DGS prefers that review of rate options take place in each utility's general rate case. The Industrial Users prefer review in the ECAC proceedings.

The parties seem to agree that nothing would be gained by consolidation of the different utilities' proposals, and we agree. After considering these comments, we conclude that under most circumstances the best forum for presenting rate options is each utility's general rate case. The GRC offers an opportunity to consider how the proposals would affect other classes and permits overall rate design to include the influence of any proposals that are approved. We share PSD's concern about overloading ECAC cases. However, when a particular ECAC proceeding is considering extensive revisions in rate design, entertaining proposals for rate options would add little additional burden. Thus rate option proposals may be received in ECAC proceedings that include consideration of extensive revisions in rate design. In all other ECAC proceedings, proposals for rate options will be considered only if the utility demonstrates an urgency or compelling need to examine the proposal in that particular ECAC proceeding.

In addition, we agree with several parties that we should maintain some flexibility for consideration outside of the ECAC and general rate cases. In extraordinary circumstances, when timing does not permit examination in the ECAC or general rate case, we will consider accepting separate applications for approval of rate proposals. These applications should be filed only when conditions approach an emergency state, such as if unexpected changes in economic conditions lead an entire industry to consider leaving the system. Any such application should contain a detailed explanation of the circumstances that justify this extraordinary procedure.

V. Delaying the Transition Date

In D.87-05-071, we set April 1, 1988, as the transition date. The transition date has several effects. First, it is the date when the Electric Revenue Adjustment Mechanism (ERAM) and the Attrition Rate Adjustment (ARA) will be eliminated for what we are now calling the less restricted class. Second, it is the date when the revised forecast of sales and revenues to the less restricted class, which is made necessary by the elimination of ERAM, takes effect. Third, it is the date when any rates changes resulting from the removal of the ARA will take effect. Fourth, it is the date when shortfalls resulting from special contracts with members of the less restricted class will no longer be recovered through ERAM. Fifth, sales and revenues before this date form the basis for adjustments to the ERAM balancing account to reflect the contribution or responsibility of the less restricted class.

Because of the need to synchronize all these elements, because of the complexity of the various effects, and because this case is proceeding more slowly than we expected last May, we now believe that it is appropriate to delay the transition slightly. Therefore, we will replace the April 1 transition date with a new transition date of September 1, 1987.

VI. Risk Allocation

From the various comments we have received in response to D.87-05-071 and the workshops, we perceive that some confusion exists about how we intend to allocate the risk of variations in sales and revenues after we have removed the protections of ERAM for some classes. In particular, some parties have asked how the risk of a persistent reduction in sales and revenues resulting from bypass and special contracts should be allocated between the utility and ratepayers. In hopes of clearing up any lingering confusion about our policies, we will briefly discuss how risk should be allocated in light of the regulatory revisions we adopted in D.87-05-071.

By way of background, we note that under the existing system of regulation, all risk of sales and revenue variation is assigned to ratepayers. ERAM acts to recover additional revenues from ratepayers when sales are less than expected, and rates are lowered if the utility collects higher than forecasted revenues. This system worked well when sales variation resulted mainly from cyclical and roughly symmetrical changes, such as variations in economic and meteorologic conditions.

Recent circumstances persuaded us to modify this system of regulation. One such circumstance is the existence of a short-term capacity surplus in California. This surplus resulted largely from the addition to rate base of several large, capital-intensive baseload plants. Under normal ratemaking principles, recovery of capital costs occurs primarily during the early years of a plant's operation, resulting in a noticable increase in rates to customers. The lower fuel costs of such plants do not entirely offset the early capital costs. But the lower fuel costs allow the utility to produce incremental units of power at costs well below the rates charged for those incremental units; one result is that short-run marginal costs are below average costs.

The increase in rates resulting from these large rate base additions makes it attractive for more and more customers to consider building and operating their own generation units, especially when these units can be integrated with industrial processes through cogeneration. This tendency has been accelerated by developments in cogeneration technology. With these economic and technological developments, we have seen considerable self-generation and bypass of the utility's system in recent years. With each customer who leaves the system, a smaller customer base remains to bear the large fixed costs of the utility's rate base.

In reaction to the rise of self-generation and bypass of the utility's system, we have permitted utilities to attempt to retain some customers on the system by offering special contracts at rates that differ from the tariff rates that would otherwise apply to those customers. Because of the gap between short-run marginal costs and average costs, utilities can supply power at reduced rates and still receive revenues that exceed the costs of production.

But use of these special contracts created another concern. Because of ERAM, the utility, the entity we were relying on to negotiate these special contracts, had no direct economic incentive to negotiate a high price or, for that matter, even to attempt to retain customers on the system. In order to align incentives with the behavior we hoped to encourage, we decided to remove ERAM for the revenue from customers most likely to bypass the system and most likely to be able to take advantage of an offer of a lower electricity rate for incremental sales. One major reason for removing ERAM and the Attrition Rate Adjustment was to put utilities at risk for the results of the negotiations of special contracts with customers. We intended to provide an incentive for the utility to negotiate the highest possible price for each contract, and we wanted to give the utility the responsibility for determining how high the price could rise without losing the customer.

In the absence of ERAM, the key allocation of risk of sales and revenue variation occurs in the adopted forecast of revenues for sales to customers no longer covered by ERAM. If actual revenues exceed the level predicted in the forecast, the utility retains the excess. If revenues fall below forecasted levels, the utility must bear the loss. Thus, the utilities will have a direct economic incentive to maximize the net revenues for sales to the less restricted class.

Revenues can be maximized in three general ways. First, sales to customers who cannot present a credible threat of imminent bypass should be at tariff rates, and any special contract negotiated with potential bypassers should be at the highest rate possible for that particular customer, presumably just below the rate that would tilt the customer's decision in favor of leaving the system. Second, rates for incremental sales should be designed to maximize revenues, not necessarily sales. Lesser sales at higher rates may result in higher net revenues. Third, reducing the costs of producing power and making sales to customers in this class will increase net revenues.

One implication of using the forecast to allocate risk is that the utility's incentive to maximize net revenues from sales to the class not covered by ERAM is not affected by the level or accuracy of the forecast. This incentive exists despite the level of the forecast because any additional revenues that the utility collects from sales, less any additional costs incurred to negotiate contractual rates or to promote additional sales, will directly benefit the utility and its shareholders, either by increasing profits or reducing potential losses. Therefore, whatever the level of the adopted forecast, the utility and its shareholders are at risk for bypass in the sense that any increase in actual bypass will reduce the utility's revenues.

A second form of risk connected with the forecast is the possibility that the forecast will in some way be biased. Although this bias will not affect the utility's incentive to prevent bypass and maximize net revenues, the level of the revenue forecast is the boundary between the utility's profit and loss for sales to the less restricted class. Forecasts will always vary from actual events to some degree, but it is our intent to adopt a fair and unbiased forecast that is equally likely to be high or low compared to actual revenues for the period. If the forecasted revenues are too high because of bias, it will be less likely that the utility will be able to achieve the forecasted level of revenues, which amounts to an indirect reduction of the utility's authorized rate of return. Similarly, if the forecasted revenues are too low because of bias, it will be highly probable that the utility will achieve more than that level of revenue, which amounts to an indirect increase in the rate of return. Shareholders would be overcompensated for risk at the same time the risk of bypass and attendant loss of margin would be overstated by the artificially low forecast. The bonus to shareholders would come at the expense of other customer classes, who would be allocated a greater margin recovery as a result of the low forecast.

The utility's financial incentive to lowball the forecast indubitably exists, but we caution the utilities against manipulating the forecast. We expect the DRA in their role as ratepayer advocates to vigilantly examine every aspect of the utilities' forecasts for bias and to recommend a fair forecast of less restricted class revenues to us. The equity of our approach to competition and bypass lies in the fairness of the forecast.

Thus, we intend that our adopted forecasts will be unbiased and fair. As we stated in D.87-05-071 at p. 17:

> "The forecasts should be the best estimate of actual sales and revenues that will occur considering the regulatory revisions we adopt in this decision. The forecasts should reflect lower expected sales levels resulting from customers lost to self-generation, lower expected revenues for sales to customers who are likely to be retained on the system by use of special contracts at less than tariff rates, and increased sales and revenues for additional sales resulting from the utility's ability to offer electricity at less than tariff rates."

Our goal is to develop a forecast that, on average, is high as often and to the same degree as it is low. Put another way, if we ignore other aspects of the utility's operations, and if the forecast is accurate and the utility's actions are reasonable, the utility would exactly earn its authorized rate of return. If the utility was particularly shrewd in its dealings with large customers, it would be able to increase revenues above the forecast and raise its rate of return. If the utility was lax or unskillful, it would not receive enough revenues to earn its rate of return.

Thus, in setting the forecast of revenues and eliminating ERAM, we have placed the immediate risk of bypass on the utilities. Although the utility's incentive is not affected by the level of this forecast, it is our intent to develop a forecast that is fair and unbiased.

Another area that seemed to confuse some parties was how forecasts would be revised. D.87-05-071 stated that after the initial forecasts were adopted, they should remain in effect until each utility's next general rate case, so that the incentives would have time to operate. Subsequent revisions would occur only in the general rate case.

Some of the apparent confusion about the forecast revision concerns whether and to what extent existing special contracts would be reflected in the revised forecasts. Even if a five-year contract is signed at the very beginning of the rate case cycle, the final two years would fall into the next cycle. Some parties have wondered if the Commission intended that the actual sales and revenues from such contracts would automatically be incorporated into the revised forecast.

This problem in many ways resembles the problem raised by contracts signed just before the initial forecast is developed. We discussed this problem in D.87-05-071, at pp. 17-18:

> "If these contracts are automatically incorporated into the forecast, then the utility would have a temporary incentive to enter into many of these agreements, since the lower revenues resulting from these sales would tend to make it more likely that the utility would be able to exceed the forecast, and thus to make a larger profit from sales to this class. Automatically incorporating existing contracts into the revised forecast would also lessen the utility's incentive to negotiate the highest possible price for the sale under the special contracts. However, ignoring these contracts is also unrealistic.
>
> "Our solution is to encourage parties to examine these contracts carefully and to consider the reasonableness of the contracts in developing their forecasts of the overall sales and revenues expected from these contracts in the forecast period. If a party believes higher prices could have been obtained from customers under special contracts, then higher revenues should be incorporated in that party's forecast. We do not comtemplate, however, a detailed reasonableness review of each special contract as a part of the forecast proceeding. We stress that the goal of these proceedings is to develop a reasonable estimate of future sales and revenues for the entire LL&P class,

> and the terms of individual contracts are relevant only as a small part of a party's method for making its forecast. Parties who examine individual contracts should keep this goal in mind. Under this procedure, then, these contracts will not be automatically incorporated into the forecast, but the reasonableness of their price terms will be reflected in the forecasts sponsored by individual parties."

We went on to approve this type of review for the revision of forecasts.

We still believe that this general approach is suitable for forecast revisions. We should make clear that the nature of the review of a special contract that occurs in the Expedited Application Docket, especially after the elimination of ERAM, is not one that results in a finding that the level of prices in the special contract is reasonable and prudent. Rather, approval merely indicates that the contract's prices are high enough so that other classes of ratepayers are not unreasonably harmed. Accordingly, at the time of the forecast revision proceeding, as in the development of the initial forecast, parties can question the reasonableness of the prices in some or all of the special contracts. The utility is still responsible for making reasonable efforts to maximize revenues in this class, and the revised forecast should reflect the level of sales and revenues that result from reasonable efforts.

We anticipate that pricing terms and the volumes of sales under existing contracts will not bind our adopted forecast, and we encourage DRA and other parties carefully to examine the reasonableness, <u>in toto</u>, of the prices in each utility's portfolio of existing special contracts. Evidence of revenues from pre-existing contracts is not conclusive proof of the utility's ability to obtain revenues from subsequently negotiated special contracts.

If a party believes that the utility has not made reasonable efforts to maximize revenues, that party should propose a forecast that reflects the higher revenues that would have resulted if the utility had made reasonable efforts to maximize revenues from special contracts. Similarly, the utility may argue that the prices in its special contracts reflect extraordinary efforts and business acumen, so that the forecast of the revenues resulting from merely reasonable efforts should be somewhat lower than those resulting from its existing pool of special contracts.

We wish to stress again, however, that we do not want the forecast revision hearings to become a detailed review of many individual contracts. The concern of the forecast revision is to develop a reasonable estimate of overall sales and revenues, and it is unlikely that any individual contract will have much effect on those overall figures.

Thus, to the extent that the Commission determines in the forecast revision that bypass or reduced revenues have or will occur despite the utility's reasonable efforts to maximize revenues, some risk of bypass and reduced revenues will be shifted to ratepayers. This shift will result from setting the level of expected revenues, which, to be unbiased, should forecast any level of bypass that the utility's reasonable efforts could not prevent. Because of the lesser revenues resulting from this unavoidable bypass, remaining ratepayers may face a larger share of the utility's fixed costs.

We should again point out the the present system of regulation shifts all risks of bypass and reduced revenues to ratepayers. Our intent is to minimize the risks shifted to ratepayers in the forecast by emphasizing the utility's incentive to maximize revenues.

Ratepayers may gain in two other ways during the forecast revision. First, since the utility's incentive is to maximize net revenue, we presume that costs of producing electricity for sales to the less regulated class will be minimized. Some of this cost reduction will spill over to the benefit of other classes, and some of these reduced costs will be reflected in lower base rates and ECAC rates. Second, to the extent that the utility's reasonable efforts are successful in reducing bypass from the amount that would have occurred in the absence of incentives, relatively larger revenues will be assigned to the less regulated class, and the revenue responsibility of other classes will be proportionately lower.

It may appear that we have set an impossible task for ourselves in trying to develop a forecast of sales and revenues that the utility should be able to attain with reasonable efforts to maximize net revenues. Utilities may predictably argue that the revenues achieved from existing special contracts resulted from herculean efforts and extraordinary business acumen. Other parties will argue that even more revenues were available for the taking if only the utility had exercised ordinary business skill. And forecasts of incremental sales, in particular, will initially be based on few facts and much speculation.

We are aware of all these potential problems, but several factors persuade us that the fears about these problems are overblown.

First, we expect that the bulk of the customers in the less restricted class will continue to receive electricity under existing tariffs, so that the revenues affected by the forecasts of bypass and incremental sales should be a relatively minor part of the utility's overall revenues. The utilities have a strong incentive to refuse to negotiate a special contract with any customer who cannot present a very credible threat of imminently leaving the system. Even for those customers who must be offered reduced rates to stay on the system, the utilities should negotiate a price as close to the tariff rate as possible. Moreover, as we continue to pursue our goal of moving toward a revenue allocation based on Equal Percentage of Marginal Costs (EPMC), the gap between the tariff rates and the marginal cost of producing power should narrow, rendering self-generation somewhat less attractive and lowering the amount of revenue reductions that must be estimated because of bypass and special contracts.

Thus, most of the forecast should follow existing trends and familiar patterns. The more difficult aspects of the forecast--estimating the amount of bypass, the revenues received from customers under special contracts, and the revenues resulting from incremental sales--should have a relatively small effect on the utilities' total revenues. With time and experience, our forecasting abilities in this area should improve.

Also, if our incentive system works properly, the utilities' self-interest should provide some assurance that the price levels of special contracts are not wildly out of line.

To return to the original question, then, the risk of bypass is allocated between ratepayers and the utility and its shareholders in several ways. Solely because of the elimination of ERAM and the setting of a forecast of revenues, the utility has the immediate risk of bypass, since every dollar of lost revenue directly affects its net revenues. Thus, the risk that revenues will not reach forecasted levels because of bypass falls on the utility during the period between forecast revisions. If all other parts of the forecast of revenues are accurate, the loss of revenue because of bypass between forecast revisions will mean that the utility will not earn its authorized rate of return.

In the longer term, ratepayers bear the risk of bypass that cannot be avoided by the utility's reasonable efforts to maximize revenues from the less restricted class. The decrease in sales at tariffed levels, despite the reasonable efforts of the utility, will be reflected in each revised forecast. This means that less of the burden of collecting margin will be allocated to the utility's sales to the less-restricted class. The allocation will fall on sales to customers whose rates are subject to ERAM. Thus, the longer-term risk of declining revenues due to bypass and to the lesser revenues recovered from customers under special contracts will fall on other ratepayers. When forecasts are revised in the general rate case, they should acknowledge the reduced revenues that result from the forecast of unavoidable bypass or the necessary rate reductions given in special contracts to keep customers on the system. Assuming that the utility's revenue requirement remains constant, these lesser revenues will necessarily require a shift of revenue responsibility to other ratepayers. In this way the risk of reduced revenues from unavoidable bypass and special contracts is transferred from the utility in the short term to other ratepayers in the long term.

Our goal is to minimize both the short-term and long-term risk of underrecovery of margin by using the utility's economic self-interest as an incentive to act in a way that minimizes the risk to ratepayers, and by setting a fair and unbiased forecast that offers the utility a reasonable opportunity to achieve, and even to exceed, its authorized rate of return with regard to revenues from the less regulated class.

As a final point of clarification, we determined in D.87-05-071 that revenue shortfalls that occur before the transition date and that result from sales under special contracts would be recovered in ERAM. After the transition date, however, sales under contracts signed before the transition date with customers in the less restricted class will be treated like other revenues and will be not be recovered in ERAM. Although this point was made clearly in the text of D.87-05-071, Conclusion of Law 10 neglected to mention the transition date. We will modify this finding to clarify our intent.

Findings of Fact

1. In D.87-05-071, we requested comments on proposed guidelines for special contracts, on the definition of the LL&P class, and on the appropriate proceeding for review of proposals

for rate options. We also directed the ALJ to conduct workshops on the proposed guidelines.

2. The workshops on the proposed guidelines were held on July 27 and 28, 1987. In a ruling dated July 31, 1987, the ALJ allowed additional comments on the proposed guidelines to be filed by August 14, 1987.

3. Comments responding to D.87-05-071 were filed by PG&E, Edison, SDG&E, PSD, CEC, DGS, Industrial Users, and NRDC. Post-workshop comments were filed by NRDC, PG&E, Edison, SDG&E, PSD, Industrial Users, DGS, and Pacific Power. SDG&E also responded to certain comments of PSD on September 18, 1987.

4. The Expedited Application Docket (EAD) was established to review all special contracts that utilities entered into with potential bypassers.

5. The purpose of the guidelines for special contracts is to allow for a faster review than would otherwise occur under the EAD.

6. PG&E, Edison and SDG&E currently revise the Standard Offer No. 1 avoided energy prices quarterly to reflect changes in the price of their marginal fuels.

7. In the past, the Commission has found it useful to treat marginal transmission and distribution costs as rental charges.

8. The Energy Reliability Index (ERI) provides a readily available means of adjusting capacity costs to reflect the need for additional generation for Edison and SDG&E. The ERI may not be suitable for PG&E's system without some modification or limitation.

9. Many customers with demands of 1000 kW or greater present a credible threat of bypass.

10. There is a two-to-three year lead time required for the development and construction of a large self-generation facility.

11. It generally costs the utilities more to generate electricity during on-peak hours than during off-peak hours.

12. Higher demands at peak periods often create the need for additional generating resources.

13. With existing technologies, additional generating resources are usually more expensive and environmentally troublesome than existing resources.

14. Self-generation facilities make the most economic sense for customers when the facilities are designed to run at a high load factor.

15. NRDC made two related proposals for integrating special contracts with the utility's long-run resource needs.

16. The transition date is key to several complex events and adjustments that occur with the elimination of ERAM and the ARA for the less regulated class.

17. Several parties requested an opportunity to comment on the final guidelines for special contracts adopted by the Commission before those guidelines took effect. When the opportunity was offered, PG&E, DRA, Edison, SDG&E, NRDC, the California Energy Commission, DGS, the Industrial Users, Chevron U.S.A., and the Northern California Power Agency submitted comments.

Conclusions of Law

1. All special contracts should be reviewed under the Expedited Application Docket (EAD).

2. The EAD should be expanded to include review of special contracts for incremental sales.

3. Special contracts not conforming to the guidelines may still be approved if the utility can demonstrate that the contract is fair to other ratepayers.

4. The floor price for special contracts should at least cover the utility's cost of producing the power sold under the contract.

5. It is reasonable to adopt the SO#1 energy formula as the energy component in the floor price guideline.

6. Each utility should book a credit to its ECAC account monthly at the appropriate ECAC rates for each kilowatt-hour sold

under special contracts. Similar credits should be made to other balancing accounts to cover the incremental costs of producing power sold under special contracts.

7. It is reasonable to use the marginal transmission and distribution cost established in each utility's general rate case as the T&D component of the floor price guideline.

8. When increased load under contracts for incremental sales requires modification of the existing T&D system or acceleration of the installation of planned improvements, the contract price should recover an appropriate measure of these site-specific increased costs.

9. The floor price should include a generation component consisting of the ERI-adjusted SO#1 capacity prices. In lieu of the ERI, PG&E may use the adjustment adopted in the pending decision in A.82-04-044.

10. It is reasonable at this time to restrict the accelerated review provided by the guidelines to anti-bypass contracts with customers with demands of 1000 kW or greater and to incremental sales contracts with customers whose base demand is 1000 kW or greater.

11. For contracts designed to deter self-generation by a customer, it is reasonable at this time to limit the accelerated review provided by the guidelines to contracts with a maximum term of five years, beginning from the date the deferred self-generation plant would have begun operation. For contracts for incremental sales, it is reasonable at this time to limit the accelerated review provided by the guidelines to contracts with a maximum term of three years. Contracts should not extend into periods when forecast indicate that additional capacity will be needed to meet target reserve margins.

12. The price terms of a special contract should discourage undue on-peak consumption and should encourage the customer to flatten its load profile as much as possible.

13. It is reasonable to establish a guideline that requires the energy component of the floor price to be time-differentiated.

14. Beyond the floor price, utilities should have flexibility in developing time-of-use incentives for special contracts. This portion of the guidelines is satisfied if the differential between the on- and off-peak rate for the customer's marginal consumption is roughly the same as the differential between on- and off-peak rates in the applicable TOU tariff.

15. It is reasonable to require utilities to present customers with a menu of conservation options during negotiations for special contracts. The elements of the menu will be developed in a workshop to be held as soon as feasible. The programs included in the menu should meet the societal test of cost-effectiveness. The customer may then choose a contract based entirely on rate discounts, a contract based entirely on conservation items with all electricity sold at tariff rates, or a contract based on a mixture of rate discounts and conservation items. However, the utility's cost of the conservation items plus the net present value of any discount from tariff rates may not exceed the net present value of the total discount from tariff rates that the utility and customer would have agreed to in the absence of the conservation option. The initial source of funds for the conservation items will be the utility's authorized conservation budget for programs designed to serve the less regulated class. The utilities may file an advice letter to request additional funds, when needed, for conservation items selected by special contracts customers.

16. At present, the less restricted class should be limited to customers with demands of 1000 kW or greater.

17. Proposals for rate options should usually be considered in each utility's general rate case. If a particular ECAC case is considering extensive revisions to rate design, proposals for rate options may also be entertained in that ECAC proceeding.

18. The transition date of April 1, 1988, adopted in D.87-05-071 should be changed to September 1, 1988.

19. Conclusion of Law 10 in D.87-05-071 should be modified to read as follows:

> "10. Revenue shortfalls occurring before the transition date as a result of sales under special contracts should be recovered in ERAM. After the transition date, revenues from all special contracts will not be included in ERAM."

INTERIM ORDER

IT IS ORDERED that:

1. In order to qualify for an accelerated review, special contracts entered into by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E) must have the following elements:

   a. A floor price consisting of an energy component, a transmission and distribution (T&D) component, and a generation component. The energy component shall be equivalent to the utility's Standard Offer No. 1 energy price. The T&D component shall be based on the marginal T&D cost as established in each utility's most recent general rate case. When increased load under contracts for incremental sales requires modification of the existing T&D system or acceleration of the installation of planned improvements, the contract price should recover an appropriate measure of these site-specific increased costs. The generation component shall be based on each utility's Standard Offer No. 1 capacity price, including adjustments based on the utility's most recently established Energy Reliability Index. In lieu of the ERI, PG&E may use the adjustment adopted in the pending decision in A.82-04-044. The energy component of the floor price shall be time-differentiated.

b. The contract is entered into with a customer with a demand of 1000 kW or greater.

c. For contracts designed to deter proposed self-generation by the customer, the term of the contract is no longer than five years, commencing when the proposed self-generation facility would have begun generating. For contracts for incremental sales, the term of the contract is no longer than three years, starting when the incremental sales under the contract begin. The term of the contract may not extend into any period when forecasts indicate that additional capacity will be needed to meet target reserve margins.

d. The contract contains time-of-use that set a differential between on- and off-peak contract rate for marginal consumption that is roughly the same as the differential between on- and off-peak rates in the otherwise applicable TOU tariff.

2. At the present time, the Large Light and Power class referred to in D.87-05-071, which is more properly called the less restricted class, will be limited to customers of PG&E, Edison, and SDG&E with demands of 1000 kW or greater.

3. PG&E, Edison, and SDG&E shall book a credit to their ECAC accounts monthly at the appropriate ECAC rates for each kilowatt-hour sold under special contracts. Similar credits shall be made to other balancing accounts to cover the incremental costs of producing power sold under special contracts. Within 30 days of the effective date of this decision, PG&E, Edison, and SDG&E shall serve all parties to this proceeding with a list of such credits to balancing accounts and a description, including suggested tariff revisions, of how they propose to make such credits.

4. Utilities shall present customers with a menu of conservation options during negotiations for special contracts. The elements of the menu will be developed in a workshop to be held

as soon as feasible. The programs included in the menu should meet the societal test of cost-effectiveness. The customer may then choose a contract based entirely on rate discounts, a contract based entirely on conservation items with all electricity sold at tariff rates, or a contract based on a mixture of rate discounts and conservation items. However, the utility's cost of the conservation items plus the net present value of any discount from tariff rates may not exceed the net present value of the total discount from tariff rates that the utility and customer would have agreed to in the absence of the conservation option. The initial source of funds for the conservation items will be the utility's authorized conservation budget for programs designed to serve the less regulated class. The utilities may file an advice letter to request additional funds, when needed, for conservation items selected by special contracts customers.

5. Except in extraordinary circumstances, PG&E, Edison, and SDG&E shall present any rate option proposals in each utility's Energy Cost Adjustment Clause proceeding or general rate case.

6. The transition date of April 1, 1988, adopted in D.87-05-071 is changed to September 1, 1988.

7. Conclusion of Law 10 in D.87-05-071 is modified to read as follows:

> "10. Revenue shortfalls occurring before the transition date as a result of sales under special contracts should be recovered in ERAM. After the transition date, revenues from all special contracts will not be included in ERAM."

This order is effective today.

Dated March 9, 1988, at San Francisco, California.

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

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

Victor Weisser, Executive Director

negotiate contractual rates or to promote additional sales, will directly benefit the utility and its shareholders, either by increasing profits or reducing potential losses. Therefore, whatever the level of the adopted forecast, the utility and its shareholders are at risk for bypass in the sense that any increase in actual bypass will reduce the utility's revenues.

A second form of risk connected with the forecast is the possibility that the forecast will in some way be biased. Although this bias will not affect the utility's incentive to prevent bypass and maximize net revenues, the level of the revenue forecast is the boundary between the utility's profit and loss for sales to the less restricted class. Forecasts will always vary from actual events to some degree, but it is our intent to adopt a fair and unbiased forecast that is equally likely to be high or low compared to actual revenues for the period. If the forecasted revenues are too high because of bias, it will be less likely that the utility will be able to achieve the forecasted level of revenues, which amounts to an indirect reduction of the utility's authorized rate of return. Similarly, if the forecasted revenues are too low because of bias, it will be highly probable that the utility will achieve that level of revenue, which amounts to an indirect increase in the rate of return. Moreover, a biased, low forecast also means that other customer classes will have to bear more than their intended share of revenue responsibility and will thus pay higher rates than they should.

Thus, we intend that our adopted forecasts will be unbiased and fair. As we stated in D.87-05-071 at p. 17:

> "The forecasts should be the best estimate of actual sales and revenues that will occur considering the regulatory revisions we adopt in this decision. The forecasts should reflect lower expected sales levels resulting from customers lost to self-generation, lower expected revenues for sales to customers who are likely to be retained on the system by use of special contracts at less than tariff rates,

> and increased sales and revenues for additional sales resulting from the utility's ability to offer electricity at less than tariff rates."

Our goal is to develop a forecast that, on average, is high as often and to the same degree as it is low. Put another way, if we ignore other aspects of the utility's operations, and if the forecast is accurate and the utility's actions are reasonable, the utility would exactly earn its authorized rate of return. If the utility was particularly shrewd in its dealings with large customers, it would be able to increase revenues above the forecast and raise its rate of return. If the utility was lax or unskillful, it would not receive enough revenues to earn its rate of return.

Thus, in setting the forecast of revenues and eliminating ERAM, we have placed the immediate risk of bypass on the utilities. Although the utility's incentive is not affected by the level of this forecast, it is our intent to develop a forecast that is fair and unbiased.

Another area that seemed to confuse some parties was how forecasts would be revised. D.87-05-071 stated that after the initial forecasts were adopted, they should remain in effect until each utility's next general rate case, so that the incentives would have time to operate. Subsequent revisions would occur only in the general rate case.

Some of the apparent confusion about the forecast revision concerns whether and to what extent existing special contracts would be reflected in the revised forecasts. Even if a five-year contract is signed at the very beginning of the rate case cycle, the final two years would fall into the next cycle. Some parties have wondered if the Commission intended that the actual sales and revenues from such contracts would automatically be incorporated into the revised forecast.

This problem in many ways resembles the problem raised by contracts signed just before the initial forecast is developed. We discussed this problem in D.87-05-071, at pp. 17-18:

> "If these contracts are automatically incorporated into the forecast, then the utility would have a temporary incentive to enter into many of these agreements, since the lower revenues resulting from these sales would tend to make it more likely that the utility would be able to exceed the forecast, and thus to make a larger profit from sales to this class. Automatically incorporating existing contracts into the revised forecast would also lessen the utility's incentive to negotiate the highest possible price for the sale under the special contracts. However, ignoring these contracts is also unrealistic.
>
> "Our solution is to encourage parties to examine these contracts carefully and to consider the reasonableness of the contracts in developing their forecasts of the overall sales and revenues expected from these contracts in the forecast period. If a party believes higher prices could have been obtained from customers under special contracts, then higher revenues should be incorporated in that party's forecast. We do not contemplate, however, a detailed reasonableness review of each special contract as a part of the forecast proceeding. We stress that the goal of these proceedings is to develop a reasonable estimate of future sales and revenues for the entire LL&P class, and the terms of individual contracts are relevant only as a small part of a party's method for making its forecast. Parties who examine individual contracts should keep this goal in mind. Under this procedure, then, these contracts will not be automatically incorporated into the forecast, but the reasonableness of their price terms will be reflected in the forecasts sponsored by individual parties."

We went on to approve this type of review for the revision of forecasts.

We still believe that this general approach is suitable for forecast revisions. We should make clear that the nature of the review of a special contract that occurs in the Expedited Application Docket, especially after the elimination of ERAM, is not one that results in a finding that the level of prices in the special contract is reasonable and prudent. Rather, approval merely indicates that the contract's prices are high enough so that other classes of ratepayers are not unreasonably harmed. Accordingly, at the time of the forecast revision proceeding, as in the development of the initial forecast, parties can question the reasonableness of the prices in some or all of the special contracts. The utility is still responsible for making reasonable efforts to maximize revenues in this class, and the revised forecast should reflect the level of sales and revenues that result from reasonable efforts. If a party believes that the utility has not made reasonable efforts to maximize revenues, that party should propose a forecast that reflects the higher revenues that would have resulted if the utility had made reasonable efforts to maximize revenues from special contracts. Similarly, the utility may argue that the prices in its special contracts reflect extraordinary efforts and business acumen, so that the forecast of the revenues resulting from merely reasonable efforts should be somewhat lower than those resulting from its existing pool of special contracts.

We wish to stress again, however, that we do not want the forecast revision hearings to become a detailed review of many individual contracts. The concern of the forecast revision is to develop a reasonable estimate of overall sales and revenues, and it is unlikely that any individual contract will have much effect on those overall figures.

Thus, to the extent that the Commission determines in the forecast revision that bypass or reduced revenues have or will occur despite the utility's reasonable efforts to maximize revenues, some risk of bypass and reduced revenues will be shifted to ratepayers. This shift will result from setting the level of expected revenues, which, to be unbiased, should acknowledge any level of bypass that the utility's reasonable efforts could not prevent. Because of the lesser revenues resulting from this unavoidable bypass, remaining ratepayers may face a larger share of the utility's fixed costs.

We should again point out the the present system of regulation shifts all risks of bypass and reduced revenues to ratepayers. Our intent is to minimize the risks shifted to ratepayers in the forecast by emphasizing the utility's incentive to maximize revenues.

Ratepayers may gain in two other ways during the forecast revision. First, since the utility's incentive is to maximize net revenue, we presume that costs of producing electricity for sales to the less regulated class will be minimized. Some of this cost reduction will spill over to the benefit of other classes, and some of these reduced costs will be reflected in lower base rates and ECAC rates. Second, to the extent that the utility's reasonable efforts are successful in reducing bypass from the amount that would have occurred in the absence of incentives, relatively larger revenues will be assigned to the less regulated class, and the revenue responsibility of other classes will be proportionately lower.

It may appear that we have set an impossible task for ourselves in trying to develop a forecast of sales and revenues that the utility should be able to attain with reasonable efforts to maximize net revenues. Utilities may predictably argue that the revenues achieved from existing special contracts resulted from herculean efforts and extraordinary business acumen. Other parties will argue that even more revenues were available for the taking if only the utility had exercised ordinary business skill. And forecasts of incremental sales, in particular, will initially be based on few facts and much speculation.

We are aware of all these potential problems, but several factors persuade us that the fears about these problems are overblown.

First, we expect that the bulk of the customers in the less restricted class will continue to receive electricity under existing tariffs, so that the revenues affected by the forecasts of bypass and incremental sales should be a relatively minor part of the utility's overall revenues. The utilities have a strong incentive to refuse to negotiate a special contract with any customer who cannot present a very credible threat of imminently leaving the system. Even for those customers who must be offered reduced rates to stay on the system, the utilities should negotiate a price as close to the tariff rate as possible. Moreover, as we continue to pursue our goal of moving toward a revenue allocation based on Equal Percentage of Marginal Costs (EPMC), the gap between the tariff rates and the marginal cost of producing power should narrow, rendering self-generation somewhat less attractive and lowering the amount of revenue reductions that must be estimated because of bypass and special contracts.

Thus, most of the forecast should follow existing trends and familiar patterns. The more difficult aspects of the forecast--estimating the amount of bypass, the revenues received from customers under special contracts, and the revenues resulting from incremental sales--should have a relatively small effect on the utilities' total revenues. With time and experience, our forecasting abilities in this area should improve.

Also, if our incentive system works properly, the utilities' self-interest should provide some assurance that the price levels of special contracts are not wildly out of line.

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1. In D.87-05-071, we requested comments on proposed guidelines for special contracts, on the definition of the LL&P class, and on the appropriate proceeding for review of proposals for rate options. We also directed the ALJ to conduct workshops on the proposed guidelines.

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INTERIM ORDER

IT IS ORDERED that:

1. In order to qualify for an accelerated review, special contracts entered into by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E) must have the following elements:

   a. A floor price consisting of an energy component, a transmission and distribution (T&D) component, and a generation component. The energy component shall be equivalent to the utility's Standard Offer No. 1 energy price. The T&D component shall be based on the marginal T&D cost as established in each utility's most recent general rate case. When increased load under contracts for incremental sales requires modification of the existing T&D system or acceleration of the installation of planned improvements, the contract price should recover an appropriate measure of these site-specific increased costs. The generation component shall be based on each utility's Standard Offer No. 1 capacity price, including adjustments based on the utility's most recently established Energy Reliability Index. In lieu of the ERI, PG&E may use the adjustment adopted in the pending decision in A.82-04-044. The energy component of the floor price shall be time-differentiated.

   b. The contract is entered into with a customer with a demand of 1000 kW or greater.

   c. For contracts designed to deter proposed self-generation by the customer, the term of the contract is no longer than five years, commencing when the proposed self-generation facility would have begun generating. For contracts for incremental sales, the term of the contract is no longer than three years, starting when the incremental sales under the contract begin. The term of the contract may not extend into any period when forecasts indicate that additional capacity will be needed to meet target reserve margins.

d. The contract contains time-of-use that set a differential between on- and off-peak contract rate for marginal consumption that is roughly the same as the differential between on- and off-peak rates in the otherwise applicable TOU tariff.

2. Utilities shall present customers with a menu of conservation options during negotiations for special contracts. The elements of the menu will be developed in a workshop to be held as soon as feasible. The programs included in the menu should meet the societal test of cost-effectiveness. The customer may then choose a contract based entirely on rate discounts, a contract based entirely on conservation items with all electricity sold at tariff rates, or a contract based on a mixture of rate discounts and conservation items. However, the utility's cost of the conservation items plus the net present value of any discount from tariff rates may not exceed the net present value of the total discount from tariff rates that the utility and customer would have agreed to in the absence of the conservation option. The initial source of funds for the conservation items will be the utility's authorized conservation budget for programs designed to serve the less regulated class. The utilities may file an advice letter to request additional funds, when needed, for conservation items selected by special contracts customers.

3. PG&E, Edison, and SDG&E shall book a credit to their ECAC accounts monthly at the appropriate ECAC rates for each kilowatt-hour sold under special contracts. Similar credits shall be made to other balancing accounts to cover the incremental costs of

producing power sold under special contracts. Within 30 days of the effective date of this decision, PG&E, Edison, and SDG&E shall serve all parties to this proceeding with a list of such credits to balancing accounts and a description, including suggested tariff revisions, of how they propose to make such credits.

4. At the present time, the Large Light and Power class referred to in D.87-05-071, which is more properly called the less restricted class, will be limited to customers of PG&E, Edison, and SDG&E with demands of 1000 kW or greater.

5. Except in extraordinary circumstances, PG&E, Edison, and SDG&E shall present any rate option proposals in each utility's Energy Cost Adjustment Clause proceeding or general rate case.

6. The transition date of April 1, 1988, adopted in D.87-05-071 is changed to September 1, 1988.

7. Conclusion of Law 10 in D.87-05-071 is modified to read as follows:

> "10. Revenue shortfalls occurring before the transition date as a result of sales under special contracts should be recovered in ERAM.

After the transition date, revenues from all special contracts will not be included in ERAM."

This order is effective today.

Dated ________________, at San Francisco, California.