ALJ/RLW/tcg **

Decision 87 12 069 DEC 22 1987

ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company, for Authority to Introduce a Mandatory L6-TOU Rate to Replace its Existing A6-TOU and AL-TOU Rates and to Revise Portions of its Existing Standby Tariffs. (1 902-E)	Application 87-04-018 (Filed April 10, 1987)
In the matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY for Authority to Revise its Energy Cost Adjustment Clause (ECAC) Rate, to Revise its Annual Energy Rate (AER), and to Revise its Electric Base Rates effective November 1, 1987 in accordance with the Electrical Revenue Adjustment Mechanism (ERAM). (U 902-E)	Application 87-07-009 (Filed July 2, 1987; amended August 20, 1987)

(Appearances are listed in Appendix A.)

OPINION

I. Summary

By this order we adopt San Diego Gas & Electric Company's (SDG&E's) Energy Cost Adjustment Clause (ECAC) forecast of fuel and purchased power expense for the period November 1, 1987 - October 31, 1988. The related ECAC rate changes, changes to the Annual Energy Rate (AER) and the Electric Revenue Adjustment Mechanism (ERAM), and changes to base rates and the Major Additions Adjustment Clause (MAAC) rates result in a total revenue decrease of $141.2 million. The revenue changes are shown on Appendix B.

We also adopt revised marginal costs for SDG&E based upon the company's cost study but adjust the company's figures in several respects as recommended by intervenors.[1]

After examining the revenue allocation that would result from strict application of an Equal Percentage of Marginal Cost (EPMC) method, we find that the EPMC method should be constrained so that each customer class receives a minimum 5.0% rate decrease. Although residential and agricultural revenues are below the EPMC allocation for their classes, we will lower all rates in the context of this substantial revenue decrease. We believe that SDG&E's rates must be restructured and moved towards marginal costs in a deliberate and careful manner. Our adopted revenue allocation makes significant movement towards the adopted marginal costs and allows time for the refinement of marginal cost studies in future proceedings.

The adopted rate design, i.e. rates within each customer class, relies heavily upon an agreement submitted after hearing. The major change is the unbundling of costs for SDG&E's large commercial and industrial customers served under Schedules AL-TOU, A6-TOU, and S. Similar to the rates adopted for the other major electric utilities in California, SDG&E's large commercial and industrial rates are further unbundled to provide for higher demand and standby charges and lower energy rates. We also adopt a customer charge for residential customers as proposed by the

1 The adopted marginal costs are to a large extent of only academic interest as our revenue allocation is constrained by the use of caps. The adopted marginal costs reflect our appraisal of the evidence on this record. However, we recognize that several novel ideas were introduced in this proceeding which should be examined in SDG&E's upcoming general rate case.

Division of Ratepayer Advocates (DRA)[2] and a higher AD demand charge as proposed by SDG&E. The adopted rates are shown in Appendix C.

We also find that questions have been raised about the level of SDG&E's costs and the Commission's movement towards recovery of these high costs in fixed charges. We expect to examine SDG&E's marginal and embedded costs in the company's upcoming general rate case.

II. Procedural Background

SDG&E has filed two separate applications. The first application, Application (A.) 87-04-018, is an extraordinary request to restructure the rates charged to SDG&E's large commercial and industrial customers without changing the collected revenues.[3] The second application, A.87-07-009, is the usual ECAC filing requesting the adoption of a new forecast of fuel and purchased power expense and the implementation of the resulting changed revenue requirement through revised ECAC rates.

Prehearing conferences were held on both applications. At these conferences, several intervenors asked for consolidation of the two applications so that they could address in one proceeding the impact of both applications on customer rates. The Administrative Law Judge (ALJ) granted this request and consolidated the ECAC forecast portion of A.87-07-009 with

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2 The Public Staff Division has been renamed the Division of Ratepayer Advocates.

3 If A.87-04-018 had been approved as filed, the amount of revenues collected by SDG&E would have changed. Although SDG&E characterized the application as revenue neutral, the imposition of its proposed standby charges would have increased revenues.

A.87-04-018. The reasonableness review portion of A.87-07-009 was kept separate.

Evidentiary hearings on the consolidated proceeding were held from September 21, 1987 to October 8, 1987. Testimony from members of the public was received on September 23, 1987. SDG&E, DRA, Utility Consumers' Action Network (UCAN), San Diego Energy Alliance (Alliance), Federal Executive Agencies (FEA), Hospital Council of San Diego and Imperial Counties on behalf of Cogeneration Hospitals (Hospitals),[4] and San Diego Mineral Products Industry Coalition (MinPros) presented witnesses and sponsored expert testimony. The City of San Diego (City) actively participated through cross-examination. Concurrent briefs were filed by November 6, 1987.

The ALJ proposed decision was issued on November 17, 1987. Comments on the proposed decision were filed by SDG&E, DRA, UCAN, and the Alliance.

III. <u>ECAC Forecast of Fuel and Purchased Power Expense</u>

A. <u>Adopted Forecast</u>

We adopt SDG&E's fuel and purchased power forecast as shown on Table 1.

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4 The Hospitals and the Department of General Services jointly filed a concurrent brief.

TABLE 1

Purchased Energy	$273,468,800
Geothermal Energy	0
Nuclear Generation	25,207,700[5]
Natural Gas	129,025,700
Diesel Oil	13,700
Residual Oil	1,711,700
Subtotal	$393,427,600
Diesel Writedown	254,700
Fuel Oil Inventory	1,135,000
Wheeling Expense	9,980,100
EFI Adjustment	(5,461,400)
Net Losses on Sale of Oil	0
Subtotal	$399,336,000
Less: 8% AER Revenues	(31,946,880)
NARCO Service Charge	(23,000)
Uranium Ore Costs	6,845,000
Tucson-Alamitos Capacity (300 MW)	73,290,000
Subtotal	$447,501,120
Times: Jurisdictional and Off-System Sales Factor @ 0.974959	436,295,244
Estimated 11/01/87 undercollection	(90,923,400)
Subtotal	$345,371,844
Plus: Franchise Fees and uncollectibles @ 1.2564%	4,339,252
Total ECAC Revenue Requirement	$349,711,096

This forecast was submitted in the August 20, 1987 Amendment to A.87-07-009 and is based upon more recent data than DRA's forecast. The adopted forecast combined with the most recent updates on the ECAC and ERAM balancing accounts yields a revenue decrease of $72.3 million as shown on Table 2.

5 The workpapers supporting the adjustment to the gas costs due to D.87-12-039 are to be provided to the parties.

TABLE 2

ECAC	-$93.8 million
AER	-$ 9.7 million
ERAM	$31.3 million
Total	-$72.3 million

B. Residual ECAC Issues

Although SDG&E and PSD agreed on the amount of the revenue decrease, they continue to disagree over the ratemaking treatment of the capacity charge to be paid to Tucson-Alamito, revision of the AER to reflect the Commission's decision in the OII/OIR Gas Implementation proceeding, I.86-06-005, and the proper ratemaking treatment of fuel oil inventory.

1. Tucson-Alamito Capacity Charge

On June 30, 1987, SDG&E filed at the Federal Energy Regulatory Commission (FERC) a complaint to determine the rights and obligations of SDG&E and the Alamito Company[6] under a purchased power agreement. SDG&E alleges in this complaint that the scheduling practices and requirements of Alamito have reduced the firm capacity available to SDG&E under the contract from 400 MW to 100 MW. Until this complaint is resolved by the FERC, SDG&E is withholding payment for 300 MW of capacity. Thus, SDG&E currently is paying Alamito for only 100 MW of firm capacity. However, SDG&E's ECAC forecast reflects payment for the full 400 MW of capacity to Alamito.

SDG&E believes that its forecast incorporating the full 400 MW capacity payment to Alamito is appropriate since the outcome of the FERC litigation is problematic. SDG&E submits that the probability and timing of FERC reforming the agreement from 400 MW

6 Tucson Electric Power Company controls the dispatch of power purchased from the Alamito Company. Thus, SDG&E's communications have been with Tucson personnel although Alamito is the responsible party.

to 100 MW is unknown. SDG&E points out that if it does win its case at FERC, then 92% of the dollar benefits from this victory will flow to the ratepayers while only 8% will flow to the shareholders. SDG&E believes that the purpose of this ECAC/AER split is to allocate benefits between ratepayers and shareholders and thereby to give utility management an additional incentive to lower energy costs.[7] For this reason, SDG&E opposes a recommendation of the City that the Alamito capacity payment should be given 100 percent ECAC balancing account treatment.

If SDG&E were to lose the FERC litigation, then SDG&E could be forced to pay Alamito the withheld 300 MW capacity payment. SDG&E argues that this later payment could result in a significant upward rate shock if SDG&E is not allowed to recover the full 400 MW payment through ECAC now.

The City, UCAN, and DRA all recommend that this forecast should reflect payment for the full 400 MW capacity to Alamito subject to 100% ECAC balancing account treatment. The City points out that without provision for balancing account treatment, SDG&E will recover in the AER about $5,863,200 for capacity costs that it is not currently paying. If the Commission does not desire to make 100% of the Alamito payment subject to balancing account treatment, then the City submits that SDG&E's AER expenses in the forecast

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7 An electric utility's fuel and purchased power expense is recovered through an ECAC rate and an AER. Both the ECAC rate and the AER are based upon a forecast of the utility's fuel and purchased power expense over a one year period (the forecast period). The ECAC rate is subject to a balancing account and is adjusted to reflect recorded differences in actual expenses from the forecast of fuel and purchased power expense. The AER is not subject to a balancing account. The utility's shareholders absorb any difference in actual energy expense from the forecast expense underlying the AER. SDG&E recovers 92% of its fuel and purchased power expense through an ECAC rate and 8% through an AER. This 92%/8% "split" is based upon the amount of earnings fluctuation the Commission has determined that SDG&E can withstand.

period should be reduced by $5,863,200. UCAN points out that SDG&E will reap some of any benefit resulting from the FERC litigation since the company began withholding payment from Alamito on June 1, 1987 and the Commission will not be able to order balancing account treatment for this expense until December, 1987.

We adopt the City's proposal for 100% ECAC balancing account treatment of the Alamito capacity payment. This procedure has been adopted on other occasions when the payments were substantial and the amounts were dependent upon the outcome of litigation. At this point in time we cannot predict what the outcome of the FERC litigation will be. If the full 400 MW payment is reflected without 100% balancing account treatment, then we would be compelling ratepayers to pay nonrefundable rates reflecting costs that SDG&E is not paying. If we recognize only the current 100 MW payment, then we would be exposing shareholders to the risk that SDG&E may lose the litigation and have to pay the withheld 300 MW charge to Alamito and then recover only 92% of that payment from ratepayers. Neither result is satisfactory. If we were to adhere to the ECAC/AER ratemaking approach, then we might recognize some intermediate level of capacity payment such as 250 MW. We elect instead to provide for 100% ECAC balancing account treatment of the withheld capacity payments including interest payments to avoid speculation on the outcome of SDG&E's FERC complaint and to ensure that neither ratepayers or shareholders are unfairly penalized.

2. OII/OIR Gas Implementation Decision

SDG&E based its ECAC forecast upon then current rates for gas. SDG&E was fully aware that the gas charges would be changed in the pending OII/OIR Gas Implementation proceeding but expected the Commission to issue a decision implementing these changes before this ECAC application is decided. However, since the gas proceeding has fallen behind schedule, SDG&E now believes that the implementation of the revised gas rate structures may not occur before an ECAC decision is issued. Since the gas rates to be adopted by the Commission may differ substantially from the current rates, SDG&E proposes that it be allowed to file an advice letter modifying the adopted AER when the gas OII/OIR implementation results are final.

SDG&E argues that the AER mechanism was not intended to put either ratepayers or shareholders at risk for the unprecedented transitional problems now occurring in the gas industry. SDG&E submits that the Commission can easily avoid an inequitable result by allowing the company to file an advice letter revision reflecting the adopted utility electric generation gas charges which should be almost entirely fixed charges.

DRA opposes SDG&E's suggested advice letter procedure. DRA points out that once an AER is in place, the Commission has not allowed changes to reflect increases or decreases in fuel costs with the exception of a nuclear plant entering service. DRA maintains that the parties strive to make their best estimates of fuel costs and then live with the results until the next AER revision date. DRA contends that there is no reason to single out gas expenses for unique treatment. While current gas costs may be difficult to predict, DRA argues that other expenses such as purchased power prices are equally difficult to predict.

DRA further argues that SDG&E is selective in its request for special ratemaking treatment. DRA observes that when the Commission first allowed SDG&E to purchase spot gas and to transport that gas, the company did not ask that its then effective AER be reduced to reflect lowered gas expense.

To the extent we can recognize changed gas prices for SDG&E in this ECAC application, we will do so. However, we are unwilling to modify the AER procedure to allow for advice letter revision during the forecast period. The main purpose of the AER is to fix the company's expected fuel and purchased power expense at a single point in time and to have the shareholders absorb any fluctuations from the adopted level. Approval of an advice letter revision would substantially undercut the purpose and the effect of the AER. And as pointed out by DRA, there is no assurance that the company would make equal efforts to file advice letters reducing the AER.

Since issuance of the ALJ proposed decision, the Commission has issued a decision on the gas implementation proceeding. We have adjusted the adopted gas costs to reflect this decision.

3. Fuel Oil Inventory

DRA has proposed that the ratemaking treatment of the carrying cost of fuel oil inventory should be changed so that the company would receive a "lump sum" for this expense which would not be adjusted to reflect actual expenses in the forecast period. Essentially, DRA is recommending that SDG&E recover its entire fuel oil inventory carrying cost through the AER.

DRA asserts that this removal of balancing account treatment for fuel oil inventory carrying cost is consistent with the Commission's recent statements that utilities should not be insulated from the results of their management decisions by balancing accounts but should experience firsthand the gains and the losses resulting from their decisions. DRA also points out that the Commission has adopted this approach for Southern California Edison Company.

SDG&E responds that this "lump sum" approach will create perverse incentives for utility management. SDG&E argues that to treat one energy expense differently than other related energy expenses would create incentives for management to focus on inventory costs more than other energy costs.

SDG&E further responds that, if adopted, the "lump sum" proposal will not simplify the Commission's reasonableness review, as contended by DRA. SDG&E maintains that the Commission still will have to closely review the relationship between inventory levels, oil burns, and shortage costs.

Finally, SDG&E asserts that the existing ECAC/AER procedure gives it an adequate incentive to keep all energy costs, including the carrying cost of fuel oil inventory, as low as possible consistent with the provision of reliable service.

We decline to adopt DRA's "lump sum" approach for fuel oil inventory. We find no explanation as to why this particular energy expense should be segregated from other expenses and given different treatment. The rationale offered by DRA could be applied to other energy expenses, not just to the carrying cost of fuel oil inventory. Yet DRA does not explain why only fuel oil inventory and not purchased power or nuclear production or gas expenses should receive "lump sum" treatment. We agree with SDG&E that the isolated treatment of a single energy cost could create perverse incentives for utility management. This was one reason why we revised our original ECAC/AER procedure which did not result in the uniform treatment of all energy expenses. We will not retrace our steps and return to a procedure equivalent to the placement of fuel oil inventory carrying cost in the AER.[8]

IV. Marginal Costs

All parties agree that the goal of the Commission is to adopt marginal cost-based rates. However, the parties do not agree on what SDG&E's marginal costs are or the extent to which SDG&E's rates should be based upon its marginal costs.

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8 If DRA believes that the utility should accept more of the risks and the benefits of its fuel and purchased power cost management, then a straightforward approach would be to recommend an increase of the AER percentage. This approach would treat all energy expenses in a consistent manner.

A. SDG&E's Proposed Marginal Costs

SDG&E's marginal cost witness J. S. Parsons explained that there is an established hierarchy of marginal cost components: energy, generating demand, transmission demand, distribution demand, and customer cost. Parsons testified that the variation among customer classes increases going down this hierarchy as the costs get closer to the individual customer service. Thus, while the energy component will not vary much among customers, the individual customer costs can be significantly different. Parsons stated that the current focus of the Commission and consequently of SDG&E is on the further definition of marginal customer costs.

SDG&E has calculated marginal customer costs based on actual work orders from recent installations. SDG&E recognizes that the implementation of these calculated customer costs through EPMC could result in a disproportionate impact on residential customers. SDG&E stands by its cost study and believes that the EPMC method can be constrained through the use of caps, such as the minimum 2.5% decrease that SDG&E has proposed. SDG&E urges the Commission to determine the most accurate marginal costs and then to make the necessary pragmatic adjustments in the revenue allocation.

1. Marginal Energy Costs

SDG&E states that there is no meaningful disagreement on marginal energy costs. SDG&E has used the QFs in/QFs out methodology used and adopted in last year's ECAC and the 1986 Test Year General Rate Case.

2. Marginal Capacity Costs

SDG&E asserts that it and DRA have relied upon estimates of capacity costs provided by the Commission in the 1986 ECAC (D.87-01-051). SDG&E also states that it has no objection to the refinements proposed by FEA and the Alliance which more accurately calculate the marginal capacity costs of each customer class given unit marginal capacity costs.[9]

3. Marginal Customer Costs

SDG&E states that unlike prior Commission proceedings there is an extensive record on marginal customer costs. SDG&E believes that it has submitted a detailed work order study on the costs of providing access to the system to an additional customer.

SDG&E asserts that these costs consist of some portion of the equipment between the substation and the customer. A convenient analytic break is the final line transformer. SDG&E states the equipment from and including the transformer to the customer is dedicated to specific customers and thereby may be directly assigned to a customer class. This portion of the system is referred to as TSM or Transformer, Service drop and Meter. The equipment from the high side of the transformer to the substation may serve more than one customer class and is considered part of the common distribution system.

SDG&E asserts that unlike DRA it has included in its TSM estimate all costs from the high side of the transformer through the secondary system to the service drop and to the meter. SDG&E's estimates are based upon actual work orders and include the transformer and associated equipment, labor and transportation, the secondary connection to the transformer, the secondary cable and conduit, the secondary handhole and connections to the secondary and service cables, the service cable and conduit, and the meter

9 SDG&E and DRA allocated capacity costs among customer classes by converting the dollar per kilowatt capacity costs into cents per kilowatthour by dividing the allocated capacity costs by the total hours in the time period. The time period costs then were determined by multiplying the cents per kilowatthour figure by kilowatthours consumed by the class in the time period. FEA and the Alliance simply multiply marginal cost per kilowatt by the kilowatt demand for each class.

material cost, meter testing and associated labor and transportation.

SDG&E's TSM estimates are based upon actual work orders obtained from its operating districts showing recent new customer installations. To estimate the cost of hooking up a new residential customer in single-family detached homes, SDG&E reviewed work orders for 228 customers judged to be representative of the residential class. A similar process was followed for each customer class with the exception of large TOU and agricultural classes for which no typical recent new customer installations could be found.

SDG&E states that its methodology and the empirical data are not questioned by any party. According to SDG&E, the only criticism is of the results. However, SDG&E maintains that the parties have based their criticisms upon invalid comparisons.

SDG&E states that the higher cost estimates it has calculated for "meters" and "services" are not surprising since the estimates used last year were only nominally based upon the same costs. SDG&E points out that many actual costs were not included in last year's estimates. The current estimates of costs are based upon the actual work orders and include much more than the FERC account definitions of meters and service drops which DRA relies upon.

SDG&E objects to DRA's primary recommendation that the Commission use DRA's customer cost estimates for Southern California Edison Company (SCE) as a proxy. SDG&E points out that DRA has presumed that the SDG&E and the SCE systems must be similar without making any study of the actual equipment used by the two electric distribution systems. DRA's witness on marginal costs acknowledged that he did not know if the SDG&E and SCE systems use different types of transformers, operate at different primary voltage levels, and employ different designed maximum voltage drops.

SDG&E submits that the burden is upon DRA to show that SDG&E and SCE incur the same, or very close to the same, costs. The burden is not upon SDG&E to show otherwise. Until DRA justifies the use of SCE as a surrogate, SDG&E maintains that the DRA primary recommendation must be rejected.

SDG&E also argues that DRA's secondary recommendation should be rejected. DRA recognized that the Commission might prefer not to use estimates derived for SCE as a proxy for SDG&E estimates and recommended that the Commission carry over the customer cost estimates adopted in last year's ECAC decision. However, SDG&E observes that those estimates include the cost of meters and service drops but exclude transformers. SDG&E also points out that even though DRA's secondary recommendation excludes transformer cost, it is higher than the primary recommendation which consists 70% of transformer costs. SDG&E submits that this discrepancy between DRA's primary and secondary recommendations shows that DRA's recommendations are result-oriented rather than accurate marginal cost estimations.

Apart from TSM estimates, SDG&E has allocated some portion of the common distribution system between the high side of the final line transformer and the substation to marginal customer costs. DRA has allocated no common distribution costs to marginal customer costs.

SDG&E allocated to customer costs 25% of the energized equipment and 50% of the non-energized equipment of the common distribution system. These allocation percentages are SDG&E's best estimates of the appropriate allocation of common distribution cost between demand and customer. While these percentages are admittedly round numbers, SDG&E argues that they are demonstrably better than DRA's estimate of zero.

B. <u>DRA Proposed Marginal Costs</u>

DRA argues that the Commission should not adopt SDG&E's marginal customer costs because under the EPMC method they would increase residential rates by 17% and would decrease large commercial and industrial rates by about 25%. DRA urges the Commission not to adopt a marginal cost study that would result in such drastic revenue allocation changes without very good evidence.

DRA contends that the evidence of marginal customer costs offered by SDG&E is suspect because the numbers are much higher than the estimates adopted last year and the marginal costs DRA has estimated for SCE. According to DRA, a comparison of TSM costs in FERC Accounts 368, 369, and 370 for SDG&E and SCE shows that SDG&E's estimated customer costs are much higher than the estimates for SCE. DRA also observes that the difference in SDG&E and SCE marginal customer costs is peculiar since the recorded rate base costs for these same FERC accounts are nearly the same for the two utilities.

Until the differences between the two utilities are explained, DRA maintains that the Commission should not adopt SDG&E's customer costs because of the impact these estimates would have on revenue allocation. DRA recommends instead that the Commission use as a proxy for SDG&E the customer cost estimates that DRA has derived for SCE. Alternatively, DRA states that the Commission could use the same customer costs adopted in last year's ECAC.

C. UCAN's Proposed Marginal Costs

UCAN recommends that DRA's TSM estimates for marginal customer costs should be adopted by the Commission. UCAN further recommends that incremental customer costs should be reduced by 29% in estimating marginal customer costs.

UCAN states that SDG&E's estimate of new customer costs appears significantly overstated. UCAN points to DRA's comparison of SDG&E and SCE estimates of customer costs by FERC account as good reason to doubt SDG&E's marginal customer costs. Before the Commission should approve SDG&E's customer costs, UCAN believes that a cost review of SDG&E's entire distribution system should be undertaken.

UCAN also offers several refinements to the marginal costs calculated by SDG&E and DRA. First, UCAN states that incremental customer costs should be reduced by 29%. UCAN believes this is appropriate because only new customers should pay the incremental costs of access to SDG&E's system. UCAN believes that existing customers should not be required to pay incremental costs but instead should be charged with the decremental cost of their access equipment. UCAN has derived an incremental/decremental method which imputes an incremental charge for new customers and a decremental charge for existing customers. The result of this method is to lower the total revenue requirement for all customer costs by 29%.

UCAN also recommends that the marginal generation capacity cost should be increased by 15% to reflect the utility's maintenance of an adequate reserve margin to provide reliable service to customers. Since SDG&E currently maintains a 15% reserve margin, UCAN proposes that the generation capacity costs should be multiplied by 1.15.

UCAN further points out that customer classes impose different requirements on the utility generation system and have different reliability needs. For example, baseload customers will impose greater reserve requirements on the system than will customers with more peaked load shapes. Also, residential customers may have a lower value for reliability than do commercial and industrial customers. UCAN believes that these matters should be given further study and consideration in marginal cost calculations before full EPMC is implemented by the Commission.

D. <u>FEA Proposed Marginal Costs</u>

FEA would allocate capacity costs among customer classes in a different manner than SDG&E and DRA have allocated them. FEA states that the correct way to allocate capacity costs is allocate them based upon customer class demands and not by customer class kilowatthours. FEA points out that SDG&E agrees that FEA's method for allocating capacity costs is an improvement of the method used by both the company and DRA in this ECAC proceeding.

FEA further recommends that SDG&E's customer costs should be adopted by the Commission. FEA believes that SDG&E's customer costs are superior since they are based upon a detailed analysis of SDG&E's system, while DRA's costs are based upon costs derived for SCE. Also, FEA points out that DRA's costs ignore common distribution costs, some of which FEA believes are properly included as customer costs.

In summary, FEA recommends adoption of DRA energy costs, SDG&E customer costs, and the FEA capacity costs.

E. Alliance Proposed Marginal Costs

The Alliance used DRA's customer costs as a conservative estimate of TSM costs. However, the Alliance includes SDG&E's allocation of common distribution costs in customer costs as the Alliance believes they are not duplicative of other customer costs and are properly assignable to a customer class.

The Alliance also recommends the same capacity allocation method used by FEA.

F. Adopted Marginal Costs

We will adopt SDG&E's marginal costs modified in several respects as recommended by intervenors. First, we adopt UCAN's incremental/decremental method for reducing the customer investment cost revenue requirement by 29%. Second, we adopt UCAN's proposal to multiply generation costs by 1.15 to reflect SDG&E's maintenance of a 15% reserve margin. Finally, we adopt the capacity allocation method recommended by FEA and the Alliance.

The concerns of DRA and other parties regarding the disparity between marginal costs by FERC account for SDG&E and SCE are not sufficient reason to reject SDG&E's marginal cost study. SDG&E's study is the only one submitted on this record which purports to estimate SDG&E's marginal costs. The critics of SDG&E's marginal cost estimates are concerned about the resulting revenue allocation under a full EPMC method. Any doubts one may have about the validity of the adopted marginal costs can be considered when the revenue allocation among customer classes is made. In other words, the results of the adopted marginal cost study can be mitigated by the use of caps and other constraints on a full EPMC allocation. Thus, the results of applying a particular marginal cost study are not a good reason to reject the study itself. A marginal cost study should be evaluated by the manner in which costs are assigned to customer classes and the estimation of those costs. We find that SDG&E's marginal cost study is the best evidence on this record of the marginal costs for its system. SDG&E's assignment of costs and estimation from actual work orders is clearly superior to the DRA's SCE proxy and the marginal costs adopted in last year's ECAC proceeding.

The three modifications to SDG&E's marginal costs that we adopt all improve the accuracy of cost estimates or the allocation among the customer classes. UCAN's incremental/decremental adjustment to customer investment costs is a more accurate estimation of costs imposed by existing and new customers. UCAN's 1.15 multiplier of generation or production costs also better reflects the utility's cost of maintaining a reserve margin. And the FEA/Alliance capacity allocation method allocates capacity costs among the customer classes based upon customer demand rather than energy consumed. FEA and the Alliance have shown that their methodology results in more precise allocations of capacity costs.

We expect that SDG&E's marginal costs will be examined more fully in the upcoming general rate case. The marginal costs we adopt here reflect the best evidence on this record. They are not intended to be a definitive statement of how SDG&E's marginal costs should be calculated or what they ideally should be. The marginal cost revenues are shown in Appendix C.

We also adopt UCAN's proposal that the reserve requirements and the reliability needs based upon value of service for the different customer classes should be studied in the 1989 TY General Rate Case. Such studies will allow for greater differentiation of capacity values and greater unbundling.

V. Revenue Allocation

Having taken the bold step of adopting a new set of marginal costs for SDG&E, we now consider the need to constrain a full EPMC revenue allocation based upon the adopted marginal costs. If unconstrained, a full EPMC revenue allocation would result in large reductions to all customer classes apart from the residential class and the agricultural class which would receive increases as shown in Appendix C. We will adopt a cap of a minimum 5.0% rate decrease for all customer classes. This cap ensures that all customers will receive a rate decrease when overall revenues are decreased. At the same time, it allows substantial movement of the customer classes towards marginal costs. The revenue allocation also is shown in Appendix C.

SDG&E also proposes to cap the revenue decrease to Schedule AD to 2.5%. Under a full EPMC revenue allocation, the AD customers would receive a 24.8% decrease. SDG&E points out that this schedule for general service demand-metered customers, which has no time-of-use rates, was closed by the Commission in last year's ECAC decision, D.87-01-051. To encourage the remaining customers on Schedule AD to migrate to time-of-use schedules, SDG&E would constrain the application of full EPMC to prevent a large reduction in the AD customer's average rate. SDG&E observes that this year only 44 customers out of some 8,000 have chosen to move to Schedule AL-TOU. SDG&E believes that a greater incentive to migrate is needed.

DRA opposes a cap on the AD Schedule. DRA believes the higher average rate for Schedule AD is enough incentive for customers to migrate to time-of-use schedules. The Alliance also protests any imposition of a cap on the decrease AD customers would receive under an EPMC revenue allocation. The Alliance argues that it would be discriminatory to deny to these customers any movement towards EPMC.

We will not constrain the revenue decrease for Schedule AD. We prefer instead to move this customer group towards its marginal costs under an EPMC allocation. We will consider phasing out Schedule AD in the upcoming general rate case.

Finally, the Hospitals ask that the estimated revenue from standby charges should be credited to the customer classes from whom the revenue is collected in proportion to the level of contracted standby demand from the class. Neither SDG&E nor DRA has included standby revenues in its determination of the revenue requirement. These standby revenues should be credited against the standby customer's class revenue requirement. We will request both SDG&E and DRA to devise an appropriate method for crediting standby revenues to a customer class.

VI. Rate Design

Through A.87-04-018 SDG&E has asked the Commission to make three major changes to the rate schedules for its large commercial and industrial customers. First, SDG&E has proposed what it believes are unbundled, cost-based rates for the large commercial and industrial class. Second, SDG&E has proposed that its tariffs for standby and interruptible standby service furnished to self-generators be revised so that the company will recover the cost of maintaining capacity to serve customers with self-generation facilities. Third, SDG&E seeks to modify its PG-QF (Parallel Generation-Cogeneration or Power Production) tariff to limit the schedule to new customers who are not demand metered and whose demands are 20 kW or less. This change is intended to close the PG-QF schedule to new demand-metered commercial and industrial customers with relatively large loads (20 to 500 kW).

SDG&E states it has requested these changes so that its rates will recover capacity costs in capacity charges and will recover energy costs in energy charges. SDG&E asserts that the existing rate structure, in which capacity costs are recovered in energy charges, makes misallocation of resources a certainty and provides encouragement for inefficient energy generation. SDG&E claims that the present AL-TOU and A6-TOU schedules force large commercial and industrial customers with high load factors to subsidize commercial and industrial customers with low load factors.

SDG&E submits that there are important reasons for the Commission to act now in reforming the rate structure. First, SDG&E states high-load factor customers will continue to shift to self generation as they recognize that they are paying energy rates that recover not only the marginal costs of energy and capacity incurred by SDG&E to serve them, but also the cost of subsidizing other commercial and industrial customers. Second, SDG&E maintains that customers are making economic decisions based upon a rate structure that does not properly reflect SDG&E's cost of service.

To facilitate rapid reformation of the commercial and industrial rate structure, SDG&E entered into an agreement with DRA, the Alliance, the FEA, the Hospitals, and the MinPros with respect to most of the major issues concerning the proposed industrial rate structure. The other parties, UCAN and the City, were aware of this agreement but chose not to participate.

The principal areas on which agreement[10] has been reached are as follows:

Retail Schedule

Customer charges should be $20 for customers served on Schedule AL-TOU and $600 for customers served on Schedule A6-TOU.

A non-coincident maximum demand charge ratchet should be employed instead of a contract demand charge.

The level of the maximum demand charge should be differentiated by voltage levels with secondary defined as under 2KV, primary as 2KV to 24.99KV, and transmission as above 25KV.

An on-peak demand charge should be imposed without a ratchet. Separate charges should be established for the summer and winter periods.

The on-peak demand charge should be applied during the summer and winter periods as they are currently defined in Schedules AL-TOU and A6-TOU.

The new charges, excluding service and standby charges, should be subject to a rate limiter of 16 cents/kWhr.

The optional time-of-use schedules, AO-TOU and AO6-TOU, should be closed to new customers effective July 1, 1988.

Standby Schedule

All waivers on the existing standby tariff should be eliminated.

A separate standby charge based on the non-coincident demand charge should be applied in addition to the rates on the new schedules.

10 The agreement is received as late-filed Exhibit 69.

> The regular retail schedule non-coincident maximum demand charge should be reduced by an amount not to exceed the contracted standby amount whenever the customer's generator is not operated.
>
> A rate limiter applicable to the monthly charges billed at the on-peak demand charge and on-peak energy rates should be established for customers taking standby service.
>
> A credit should be made for distribution payments from cogenerators.
>
> Scheduled maintenance should not be subject to on-peak demand charges provided that the maintenance schedule has been agreed to by the utility.

There are four significant areas on which agreement was not reached.

> The specific maximum demand charge and ratchet level that should be imposed; agreement was reached only on the upper and lower bounds of these charges.
>
> The level of the winter standby on-peak demand and energy rate limiter.
>
> The level of the distribution payment credit on the standby schedule.
>
> The period for which Schedule PG-QF should remain open. (All parties agreed the schedule should be closed, but urged that closure be deferred for periods ranging from six months (SDG&E) to two years (the other parties).)

We adopt the agreement submitted as late-filed Exhibit 69. We recognize that both SDG&E and the other parties have made important sacrifices to achieve this compromise.[11] We now turn to

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11 SDG&E has withdrawn from this proceeding its concept of a contract demand charge which SDG&E believed would have given commercial and industrial customers an important element of control over their demand charges.

the remaining areas of disagreement on the commercial and industrial rate structure.

A. The Non-Coincident Demand Charge

The parties agree that a non-coincident demand charge should be imposed. They disagree on the appropriate level of this charge. SDG&E proposes a charge of $4.05 per kW of demand at the secondary level, $3.22 per kW at the primary level, and $1.35 per kW at the transmission level. SDG&E states that its proposed charges are derived from the company's marginal costs of distribution as presented in the NOI for the 1989 General Rate Case. For example, the NOI distribution demand figure of $4.28 secondary was deflated by SDG&E to arrive at a 1988 level of $4.05. SDG&E further observes that the $4.05 is a compromise as the marginal cost of distribution is estimated at $7.69 per kW. Thus, SDG&E points out that its proposed charge would not recover $3.64 per kW of fixed cost.

The other parties propose charges of $3.17 per kW (secondary), $2.52 per kW (primary), and $1.06 per kW (transmission). The Alliance points out that SDG&E's original concept of a contract demand charge would have been phased in over a twenty-four month period, beginning with a $2 per kW charge and ending with a charge of $6.85 per kW. The Alliance contested the basis for the $6.85 per kW charge and opposed its adoption before the full development of marginal cost studies in SDG&E's upcoming general rate case. The Alliance urges the Commission to move cautiously until it does review SDG&E's costs in the general rate case. The Alliance points out that its proposed $3.17 charge exceeds SDG&E's original proposal of a $2.00 contract demand charge for the first twelve months of the phase-in period.

The Hospitals state that approval of the $3.17 maximum demand charge is the largest step towards unbundled rates which should be undertaken at this time. The Hospitals argue that the Commission's adoption of the higher charges proposed by SDG&E may result in the Commission having to "undo" the adopted rate structure in the upcoming general rate case. The Hospitals submit that the level of charges proposed by all parties other than SDG&E is similar to the levels adopted by the Commission for PG&E and suggested for adoption by SCE and DRA in SCE's pending general rate case.

We will adopt the non-coincident demand charges of $3.17 per kW (secondary), $2.52 per kW (primary), and $1.06 per kW (transmission). We adopt the lower set of demand charges proposed by all parties other than SDG&E because we prefer to move gradually towards the complete recovery of SDG&E's estimated fixed costs in fixed charges. These costs will be more closely examined in the general rate case. We will not leap to SDG&E's higher charges until we have looked at the underlying costs in the general rate case.

SDG&E and the other parties to the agreement also disagree as to the ratchet to be applied to the non-coincident demand charge. The purpose of a ratchet in the ratemaking context is "to improve the price signal to seasonal and intermittent customers." (Prepared Testimony of Paul Clanon, Exhibit 64, page 4-7.) SDG&E has proposed a ratchet of 75% while the other parties propose a ratchet of 50%.

SDG&E argues that a 50% ratchet will provide only token recovery of cost from intermittent customers. SDG&E originally proposed a 100% ratchet in its contract load charge but in the spirit of compromise has lowered its recommended ratchet to 75%. Below the level of 75%, SDG&E believes that the responsibility for the recovery of marginal distribution costs is unfairly shifted from intermittent customers, who created these costs, to other customers.

As noted by the Alliance, the record does not address the specific issue of a 50% ratchet vs a 75% ratchet. Lacking any evidence on this issue, we adopt the more conservative ratchet of

50% to be consistent with our stated goal of deliberate and careful movement towards unbundled rates.

B. The Winter Standby Rate Limiter

In the agreement, all parties have agreed that a standby rate limiter of $0.67 per kWh should be applied to on-peak demand and energy charges for the summer period. SDG&E believes this same $0.67 limiter should apply during the winter period. The other parties to the agreement propose a lower winter standby rate limiter of $0.26 per kWh.

SDG&E agrees in principle that a winter limiter is appropriate. However, SDG&E believes that insufficient study has been done to arrive at a specific winter level.

The Alliance states that all parties have recognized in their rate designs that SDG&E is a summer peaking utility and have allocated greater costs to the summer period than to the winter period. For example, the summer on-peak demand charges for the summer are significantly higher than the winter on-peak demand charges. The Alliance submits that to ignore this seasonal costing relationship would be contrary to cost-based rates and price signals.

We agree with the Alliance that since the adopted rate design appropriately differentiates between SDG&E's cost of service during the summer and winter seasons, the standby rate limiters should reflect a seasonal difference. We adopt the lower winter standby rate limiter of $0.26 per kWh.

C. Credit for Contributions to Distribution Facilities

In some instances, SDG&E's cogeneration customers pay for a portion of their distribution system. These contributions, made under Rule 21, are intended to cover installation and O&M costs not normally incurred by the utility. This practice then ensures that a customer's special requirements are met by that customer rather than borne by the customer body as a whole. The cogenerators have asked that they be given a credit against their noncoincident demand charges on the basis of their facilities payments. Since the noncoincident demand charges are intended to collect normal distribution costs, and the cost of the additional special facilities serving cogenerators is excluded, a credit would generally be improper. However, SDG&E recognizes that in rare cases a customer also may pay for a portion of its normal facilities as a part of a special fee. In this event, SDG&E is willing to recognize a credit of $0.10/kW.

The Alliance states that all other parties to the agreement have agreed that a $0.50 credit is fully supportable. The Alliance points out that a standby customer under Rule 15 is required to pay for 100 percent of the required facilities. In contrast, full requirements customers receive free allowances towards the same facilities. Since the noncoincident demand charges are designed to pay for distribution-related costs, standby customers could be paying twice for facilities already paid for under Rule 15. The Alliance points out that a credit of $1.00/kW has been adopted for PG&E. The Alliance believes that the $0.50 credit is conservative and should be selected over SDG&E's token amount of $0.10/kW.

We will adopt a credit of $0.50/kW. Using the PG&E credit of $1.00/kW as a reference, the $0.50 credit appears more reasonable. We also note testimony by the Alliance's witness on standby rates that he has calculated credits of about $0.70/kW for two San Diego facilities.

D. <u>Closing Schedule PG-QF</u>

SDG&E and DRA agree that Schedule PG-QF is a "giveaway" which "should go away" because "netting of energy is a very bad idea." However, they disagree as to how long the schedule should remain open. SDG&E urges that PG-QF should be closed within six months. DRA and other parties to the agreement recommend closure in two years.

Schedule PG-QF was instituted for facilities with output of 100 kW or less. This schedule allows small cogeneration systems to produce thermal loads at times when their electric loads are less than the output of their systems. The cogenerator may credit the excess electricity produced at these times against consumption during other periods when the site's electric load exceeds the power-generating capacity.

SDG&E states that it filed Advice Letter 701-E on March 10, 1987 requesting revision of PG-QF so that it applies to facilities of 20 kW or less. Thus, SDG&E maintains that if the new commercial and industrial rates become effective on January 1, 1988, and PG-QF is closed six months thereafter, customers will have had at least fifteen months to bring new cogeneration projects on-line. SDG&E submits that to allow the schedule to remain open for a longer period will simply encourage developers to sell as many new projects as possible before the curtain falls.

The Alliance argues that the longer period of two years should be allowed because there are several projects under development which could be affected by closure of the schedule in a shorter time. The Alliance asserts that the development and the implementation of small cogeneration systems can take as long as two years.

We are sympathetic to the needs of the small cogeneration industry but believe that a period of eighteen months should be sufficient to bring existing projects under development on-line. While SDG&E's advice letter filing was not an official pronouncement by the Commission, it was sufficient notice that closure of the schedule would be pursued by the utility. We are not willing to hold this schedule open for two years given the agreement by SDG&E and DRA that the schedule's energy netting provision is a bad idea which should go away as soon as possible. We believe an eighteen month period gives adequate notice of the impending tariff change to customers and to developers.

We also approve the request of all parties that Schedule PG-QF apply to third party situations.

E. ECAC Rate Design Issues

Most of this consolidated proceeding was devoted to the extraordinary rate restructuring proposed in A.87-04-018 for the large commercial and industrial customers. There are two remaining rate design issues[12] raised in the ECAC A.87-07-009 regarding imposition of a residential customer charge and an increase in the non-coincident demand charge for Schedule AD customers.

1. Residential Customer Charge

DRA recommends that the current residential minimum bill of $0.16 per day be replaced with a monthly customer charge of $4.80 per month. SDG&E supported this recommendation.

DRA states that cost of service pricing is important to send proper price signals to customers, even if those customers have no alternative to buying electricity from SDG&E. DRA believes that the residential class should join the movement towards cost-based rates. DRA also observes that its proposed $4.80 monthly charge is well below either embedded or marginal costs.

SDG&E states that a customer charge is preferable to a minimum bill because it sends a more accurate price signal to the customer. Unlike a minimum bill, the customer charge applies uniformly to all customers regardless of usage and therefore more accurately reflects marginal costs imposed by each customer regardless of usage. While some low usage customers may see their bills increase because of a customer charge, SDG&E maintains that other customers will see a decrease because the customer charge would reduce the energy rate.

12 DRA agrees with SDG&E's proposal to raise the Schedule A customer charge from $2.20 per month to $5.00 per month.

UCAN strongly opposes the proposed residential customer charge. UCAN asserts that a customer charge based upon incremental costs would overcharge existing customers whose true marginal costs are much lower. UCAN further argues that customer costs are not uniform among residential customers. Finally, UCAN contends that residential customers that use more energy will be subsidized by customers with lower energy demands if a residential customer charge is imposed. UCAN suggests that a moderate increase in the minimum bill is preferable if mandatory collection of additional customer costs is deemed necessary.

The City also opposes the DRA proposed residential customer charge.. The City generally opposes the concept of guaranteeing to SDG&E more revenue in fixed charges. If a residential customer charge is approved, the City states the revenue from this charge must be included in the baseline energy rate calculation, as affirmed by DRA's witness.

We do not doubt that more refined customer charges could be developed for the residential class. However, we will adopt the proposed $4.80 charge as it is below both embedded and marginal costs for residential customers. The imposition of a residential customer charge is consistent with our movement of all other customer classes towards unbundled cost-based rates. The revenue from this charge is to be included in the baseline calculation.

2. Increase of Schedule AD Demand Charge

Schedule AD is one of two schedules for the Small and Intermediate Commercial and Industrial Class. Customers whose monthly peak demands fall between 20 kW and 500 kW are served under this schedule.

Schedule AD consists of a $10.00 customer charge, a $4.00/kW demand charge, and per kWh energy rates. SDG&E proposes to raise the demand charge to $5.00/kW as the current demand charge is far below the combined marginal costs of generation, transmission and distribution. SDG&E also believes that the slight increase in the demand charge will give a price signal to AD customers to migrate to time-of-use schedules.

DRA states that an increase of the demand charge is not necessary to induce migration from Schedule AD to other schedules with time-of-use rates. DRA submits that the higher average rate under Schedule AD is a sufficient incentive for customers to migrate.

We approve the small increase in the demand charge to $5.00/kW. The increase is modest when measured against the marginal costs for the customer class. We note that SDG&E has withdrawn its restriction on the number of customers that may move from Schedule AD in a given year so that customers that are induced to migrate because of the higher demand charge are not prevented from moving to another schedule.

The adopted rates are shown in Appendix C.

VII. A Review of SDG&E's Costs

Today, the cardinal virtues of any rate order are a careful estimate of revenue requirement, a fair analysis of marginal costs, and a purposeful movement of rates towards marginal costs restrained by a temperate revenue allocation. After paying due respect to each of these qualities, it would be a cardinal sin to ignore the larger issues raised by the San Diego business community over the level of SDG&E's costs.

This consolidated proceeding is limited to a forecast of SDG&E's fuel and purchased power expense and the allocation of that expense among the customer classes. In addition, we undertook an extraordinary revision of the large commercial and industrial rates, a rate design that ordinarily would have been accomplished in a general rate case. In response to this extraordinary rate revision, the Alliance and the Hospitals brought forward many representatives of the business community that spoke out against the utility's proposals and complained bitterly about the prospect of being compelled to pay for the utility's high fixed costs. (Transcript Volume 3, Public Participation Hearing of September 23, 1987). In addition, the Alliance submitted expert testimony analyzing SDG&E's costs. While this is not the appropriate proceeding to review SDG&E's embedded costs, we will summarize the Alliance's showing and commit ourselves to an examination of SDG&E's persistently high costs in the upcoming general rate case.

The Alliance states that the single fundamental reason for bypass of SDG&E's electric system is not the present bundled rate structures but the overall rate levels. The Alliance states that all of SDG&E's customers--commercial, industrial, and residential--pay the highest rates in the United States. The Alliance observes that SDG&E's rates in effect on January 1, 1987 were frequently the highest of over 200 utility jurisdictions.

The Alliance undertook a comparative analysis of SDG&E's costs to determine why SDG&E's rates were so high and concluded that SDG&E's rates are the result of high expense levels in many areas. Using operation and maintenance expense data from 1980-1985 for 140 utilities, the Alliance found that SDG&E's expenses were always within the ten highest, ranging from third to eighth. Even after fuel and purchased power expense was eliminated, SDG&E still ranked within the ten highest for 1982-1984 and was twelfth highest in 1985.

The Alliance has analyzed the lack of hydro resources in SDG&E's resource mix to determine how the unavailability of this low cost resource affected SDG&E's rate levels. For 1986, SDG&E obtained 35% of energy sales from oil and gas units, 22% from nuclear, and the remaining 43% from power purchases. The Alliance asserts that this resource mix was typical for SDG&E in recent years and should continue through 1991. The Alliance then developed a subset of 23 utilities whose generation resources in the categories of steam, nuclear, and hydro were within 10% of SDG&E-owned resources. Even when compared to this subset, SDG&E's fuel and purchased power expense was 78-143% higher than the average. The remaining operations and maintenance expense was 27-54% above the average.

The Alliance also investigated SDG&E's claim that low customer sales have caused higher rate levels. Here the Alliance examined expense levels on a dollar per kilowatt basis. Again, the Alliance's results show that SDG&E is above the average when compared to the other utilities.

The Alliance observes that a utility's rates reflect operating expenses, taxes, and a return on capital. On an individual basis, SDG&E ranks high in all of these areas. When taken together, SDG&E's rates become the highest in the country. The Alliance recommends that the Commission closely scrutinize all of SDG&E's revenue requirement expense items in an effort to control SDG&E's costs and the resulting bills to all customers. We will do so in SDG&E's upcoming general rate case.

VIII. Coordination With Other Proceedings

We are using the present offset rate proceeding as a forum to implement rate design policy. In order to design rates we must compile company revenues from all rate elements, including base rates and MAAC rates, not just offset revenues.

Because this situation is new, we are faced with the need to determine the appropriate base rate revenues for rate design purposes. If base rates are left unchanged, then base rate revenues will exceed the ERAM margin authorized in the utility's most recent general rate case, due to increases in sales since that time.

Although a new sales forecast is now available, we will allow SDG&E to continue its present level of base rates. SDG&E

has not had the opportunity to argue the issue in this case and, when considered in conjunction with the utility's pending general rate proceeding, this will afford SDG&E's ratepayers a modest improvement in rate stability.

However, in I.86-10-001 or the next time a new electric sales forecast is litigated, whichever opportunity comes first, we invite utility testimony on this issue.

All of the adopted revenue changes incorporated into the presently authorized rate design are shown on the table in Appendix B. The effect of sales changes to base rate revenues is shown on lines 1 and 2 of the table.

Because the total revenue decrease is substantially greater than the decrease contemplated by the signatories to the stipulation, we will adjust the rate structure proposed in the stipulation by proportionately reducing the demand and the energy charges. The adopted rates are set forth in Appendix C.

Findings of Fact

1. SDG&E's fuel and purchased power forecast for the period November 1, 1987 - October 31, 1988 is based upon more recent data than DRA's forecast.

2. The ECAC, AER and ERAM rate changes together produce a total revenue reduction of $72.3 million.

3. SDG&E currently is paying Alamito for 100 MW of capacity although its ECAC forecast reflects payment for 400 MW of capacity.

4. SDG&E has filed a complaint with FERC regarding the capacity payment that should be made to Alamito.

5. The outcome of the FERC litigation is unknown and cannot be predicted with any degree of confidence.

6. If the Alamito capacity payment is not made subject to 100% ECAC balancing account treatment, SDG&E will recover in the AER $5,863,200 for payments that it may not be required by FERC to make to Alamito.

7. A 100% ECAC balancing account treatment for the withheld Alamito capacity payment and associated interest payments will ensure that neither ratepayers nor shareholders are penalized by the outcome of the FERC litigation.

8. SDG&E has requested permission to adjust the AER by advice letter to reflect the Commission's eventual decision revising the gas rate structure in A.86-06-005.

9. The AER is intended to fix the company's fuel and purchased power expense at a single point in time.

10. Shareholders are to absorb any recorded differences in fuel and purchased power expense from the AER.

11. DRA has proposed that SDG&E's fuel oil inventory be given "lump sum" ratemaking treatment equivalent to placing the carrying cost of fuel oil inventory in the AER.

12. DRA's "lump sum" approach would single out fuel oil inventory for different ratemaking treatment.

13. The isolated treatment of fuel oil inventory proposed by DRA could result in perverse incentives for utility management to focus on inventory costs more than other energy costs.

14. SDG&E's marginal cost study is the only study submitted in this proceeding which purports to measure the costs of service on SDG&E's system.

15. UCAN has shown that the customer investment revenue requirement for existing and new customers should be reduced by 29% under an incremental/decremental approach.

16. UCAN has recommended that marginal generation costs should be multiplied by 1.15 to reflect SDG&E's maintenance of a 15% reserve margin.

17. FEA and the Alliance have shown that their method of allocating capacity costs among the customer classes is more accurate than the allocation method used by SDG&E and DRA.

18. A cap of a minimum 5.0% rate decrease is appropriate in the context of a substantial revenue decrease.

19. The revenue decrease to Schedule AD should not be constrained so that this customer group can be moved towards its marginal costs.

20. SDG&E and DRA should devise a method whereby standby revenue can be credited to the proper customer class.

21. SDG&E, DRA, the Alliance, the FEA, the Hospitals, and the MinPros have entered into an agreement on the rate structure for large commercial and industrial customers.

22. The agreement is a major step towards unbundling SDG&E's rates and is a reasonable compromise among the signatories.

23. Noncoincident demand charges of $3.17 per kW (secondary), $2.52 per kW (primary), and $1.06 per kW (transmission) are preferable as they are more consistent with a gradual movement towards the recovery of fixed costs in fixed charges.

24. A 50% ratchet for the noncoincident demand charge is preferable as it is the more conservative choice and is consistent with a deliberate and careful movement towards unbundled rates.

25. A winter standby rate limiter of $0.26 per kWh is approriate as SDG&E is a summer peaking utility, and greater costs should be allocated to the summer period than to the winter period.

26. A credit of $0.50/kW for distribution facilities is appropriate where customers have paid for normal distribution facilities as part of a special facilities fee.

27. Closure of the PG-QF Schedule within eighteen months of the effective date of the adopted rates is sufficient time for small cogeneration projects under development to come on-line.

28. A residential customer charge of $4.80 per month is consistent with cost-based rates as the charge is below both embedded and marginal costs.

29. An increase of the Schedule AD demand charge from $4.00/kW to $5.00/kW is a modest increase when measured against the marginal costs for the customer class.

30. The Alliance has shown that SDG&E's costs as compared to other utilities' costs are above average in all expense categories and that these costs should be closely scrutinized in the upcoming general rate case.

31. The revenue changes due to adjustments to SDG&E's base rates should be flowed through the revenue allocation and the rate design adopted in this proceeding.

32. The rate structure proposed in this stipulation should be adjusted so that the demand and energy charges are reduced proportionately.

33. This order should take effect on the date of issuance so that the revised rates can become effective on January 1, 1988.

Conclusions of Law

1. The withheld Alamito capacity charge should be given 100% ECAC balancing account treatment since the amount of this payment is substantial and subject to the outcome of litigation at FERC.

2. The revenue allocation based upon an EPMC allocation constrained by a cap of a minimum 5.0% rate decrease is a fair balancing of the need to move rates towards marginal costs with the need to avoid disruptive rate changes.

3. The agreement of the parties on the basic structure of the large commercial and industrial rate schedule is a reasonable compromise based upon the evidentiary record in this proceeding.

4. The rates shown in Appendix C are just and reasonable and should be adopted.

O R D E R

Therefore, IT IS ORDERED that:

1. Five days after the effective date of this order and no later than December 29, 1987, San Diego Gas & Electric Company (SDG&E) shall file revised tariffs effective January 1, 1988 reflecting the rates as shown in Appendix C.

2. The 300 MW capacity payment and related interest payments to Alamito Company is subject to 100% Energy Cost Adjustment Clause (ECAC) balancing account treatment.

3. SDG&E and the Division of Ratepayer Advocates (DRA) shall devise a method for crediting standby revenues to the appropriate customer class.

4. Schedule PG-QF shall be closed to facilities above 20 kW by June 30, 1989, eighteen months from the effective date of the adopted rates. The schedule also shall be revised to apply to third party situations.

5. A credit of $0.50/kW shall be given to customers that have paid for normal distribution facilities in special facilities charges.

6. Schedules AO-TOU and AO6-TOU shall be closed to new customers as of July 1, 1988.

7. SDG&E and DRA shall study reserve requirements and the reliability needs based on value of service for the different customer classes in the 1989 TY General Rate Case.

8. SDG&E and DRA shall submit in the 1989 TY General Rate Case studies which explain why the company's costs and rates are high compared to other utilities' costs of service and rates.

This order is effective today.

Dated December 22, 1987, 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

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LIST OF APPEARANCES

Applicant: Richard W. Odgers, Roderick M. Thompson, and Don P. Garber, Attorneys at Law, for San Diego Gas & Electric Company.

Interested Parties: Matthew V. Brady, Attorney at Law, for the State of California; Dewey Baggett, Attorney at Law, for Hospital Council of San Diego and Imperial Counties; Eric Eisenman, for Transwestern Pipeline, Inc.; Gary Simon, for El Paso Natural Gas Co.; Michael Shames, Attorney at Law, for Utility Consumers Action Network (UCAN); R&W Consultants, by Paul A. Weir, and Muns, Mehalick & Lynn, by James Crosby, Attorney at Law, for San Diego Mineral Products Industry Coalition; John W. Witt, City Attorney, by William S. Shaffran and Leslie Girard, Deputy City Attorneys, for City of San Diego; William Mahn, Gilbert H. Chong, and Norman J. Furuta, Attorneys at Law, for Department of Defense for the Federal Executive Agencies; Judith Alper, Attorney at Law, for Independent Power Corporation; Gary W. Estes, for Hunter Industries; Michael L. Feori, for Intellicon, Inc.; Michel Peter Florio, Attorney at Law, for Toward Utility Rate Normalization (TURN); Robert E. Hansen, for Children's Hospital; E. G. Kiener, for Solar Turbines, Inc.; Barry Lovell, for University Energy; William K. Mahn, Attorney at Law, for Department of the Navy; Thomas Mason, for Energy Factors; Michael Meyer, Attorney at Law, for Hawthorne Engine Systems; Messrs. Morrison & Foerster, by Jerry R. Bloom, Attorney at Law, for San Diego Energy Alliance; Messrs. Morse, Richard, Weisenmiller & Associates, Inc., by Sarah Nickerson, for Bob Weisenmiller; D. John Morse, for Home Federal Savings & Loan Company; Jeff Nahigian, for Henwood Energy Services, Inc., Independent Energy Producers, and JBS Energy, Inc.; William F. Ohlhausen, for San Diego Energy Alliance; Kenneth Pickett, for Independent Power Corporation; John D. Quinley, for Cogeneration Service Bureau; Donald G. Salow, for Association of California Water Agencies; Richard T. Sperberg, for Onsite Energy and San Diego Cogeneration Association; Thomas Vargo, for Western Division, Naval Facilities Engineering Command; Harry K. Winters, for University of California; Ernest T. Fife, for Southern California Edison Company; S. N. Choudhuri, Chief, Energy & Utilities Programs,

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for the California State University; James D. Squeri, Attorney at Law, for KELCO; Reed V. Schmidt, for California City-County Street Light Association; Dian M. Gruenich, Attorney at Law, for herself; and Dr. Edward Neuner, for himself.

Commission Staff: Robert Cagen and Timothy F. Treacy, Attorneys at Law, Paul Clanon, and Bill Y. Lee, for the Division of Ratepayer Advocates.

APPENDIX B

SAN DIEGO GAS AND ELECTRIC COMPANY
Attrition Year 1988 - California Jurisdiction
Revenue Changes Adopted for Revenue Allocation and Rate Design

LINE	ITEM	PRESENT RATE REVENUES ** ($ million)	ADOPTED REVENUES ($ million)	REVENUE CHANGES ($ million)
		(a)	(b)	(c)
	BASE:			
1	Base (margin)	635.709	635.709	0.000
2	Sales change	44.249	44.249	0.000
3 *	Attrition (includes estimated 1988 effects of TRA)	0.000	(5.954)	(5.954)
4 *	Decommissioning	0.000	22.017	22.017
5 *	MAAC pre-COD transfer	0.000	138.452	138.452
6	Subtotal	679.958	834.473	154.515
	MAAC:			
7	SONGS pre-COD interim rates @ 1.897 c/kwh	239.139	0.000	(239.139)
8	SONGS pre-COD amortization	0.000	(19.140)	(19.140)
9 *	SONGS post-COD interim rates	0.000	14.287	14.287
10	SONGS post-COD amortization	0.000	0.000	0.000
11	Subtotal	239.139	(4.853)	(243.992)
	OTHER OFFSETS:			
12	CALPAC	0.000	0.000	0.000
13	ECAC	443.549	349.711	(93.838)
14	AER @ 0.327,0.250 c/kwh	41.222	31.515	(9.707)
15	ERAM amortization @ (0.282) c/kwh present rate	(35.549)	(4.298)	31.251
16	ERAM/SONGS 1 memo account (in attrition)	0.000	20.560	20.560
17	Tax Reform Act, 1987 refund		(deferred to 1988)	
18	Decommissioning tax refund		(deferred to 1988)	
19 *	SUBTOTAL (all above)	1,368.319	1,227.108	(141.211)
20	OTHER REVENUES	15.822	15.822	0.000
21	CPUC reimbursement fees @ 0.012 c/kwh	1.513	1.513	0.000
22 *	TOTAL	1,385.654	1,244.443	(141.211)

Notes: * Amounts depend on adopted rate of return, herein 12.75% ROE.
** Based on adjusted sales of 12,606.18 GWH.

Adopted base and MAAC revenues must be reduced by City of San Diego franchise fee differential for rate design purposes. Table shows correct margin.

(END OF APPENDIX B)

SAN DIEGO GAS AND ELECTRIC CO.
ADOPTED REVENUE ALLOCATION

CUSTOMER CLASS	SALES (MMKWH)	PRESENT RATE REVS (M$)	PRESENT AVG RATE ($/KWH)	MARGINAL CUST COST REVS (M$)	MARGINAL CAP COST REVS (M$)	MARGINAL ENERGY COST REVS (M$)	TOTAL MC REVS (M$)	EPMC ALLOCATION (M$)	% INC	ADOPTED CAPPED ALLOCATION (M$)	ADOPTED AVG RATE ($/KWH)	% INC
Residential	4,870	550,348	0.11301	126,114	212,876	128,407	467,397	572,694	4.1%	522,831	0.10736	-5.0%
General Service	1,490	179,132	0.12022	15,464	72,051	41,360	128,875	157,908	-11.8%	170,175	0.11421	-5.0%
GS-Demand Metered	2,667	293,257	0.10996	3,905	103,203	72,608	179,716	220,202	-24.9%	238,594	0.08946	-18.6%
Large TOU	2,430	235,211	0.09679	3,041	82,505	65,051	150,597	184,523	-21.5%	199,935	0.08228	-15.0%
Very Large TOU	903	81,726	0.09050	225	26,801	23,686	50,712	62,137	-24.0%	67,327	0.07456	-17.6%
Agricultural	178	17,888	0.10049	1,612	8,690	4,707	15,009	18,391	2.8%	16,994	0.09547	-5.0%
SUBT	12,538	1,357,562	0.10828	150,361	506,127	335,819	992,307	1,215,856		1,215,856		-10.4%
Streetlighting	77	10,736	0.13969					9,633		9,633		-10.4%
TOTAL RETAIL	12,615	1,368,318	0.10847					1,225,489	-10.4%	1,225,489	0.09715	-10.4%

APPENDIX C
Page 2

ADOPTED RATES
SCHEDULES: RESIDENTIAL, DSMF, A, AD, PA

Schedule	Customer Charge ($/Mo)	Demand Charge ($/KW-Mo)	Energy (Base) ($/KWH)	Energy (Offset) ($/KWH)	Energy Total ($/KWH)
Residential	4.80				
Baseline			0.05961	0.00537	0.06498
Non-Baseline			0.07720	0.06743	0.14463
DSMF	20.00	7.31			
Baseline			0.05026	0.00537	0.05563
Non-Baseline			0.05639	0.06743	0.12382
A	5.00	0.00	0.07964	0.03024	0.10988
AD	10.00	5.00	0.04229	0.03024	0.07253
PA	8.00	0.00	0.06297	0.03024	0.09321

A. 87-04-018, A. 87-07-009 ALJ/RLW CACD/PAC/8/1

Note: Baseline rate equals (.85 X SAR) - (Customer Charge Revenues) / (Baseline Sales)
(.85 X .09715) - (51356 $M / 2918657 MKWH) = .06498

APPENDIX C
Page 3

ADOPTED RATES
SCHEDULES: AL-TOU AND A6-TOU

					PROPOSED RATES					
			Winter	Summer	Summer			Winter		
	Customer Charge	Max Demand	On-Pk Demand	On-Pk Demand	On-Pk Energy	Semi-Pk Energy	Off-Pk Energy	On-Pk Energy	Semi-Pk Energy	Off-Pk Energy
Customer Class	($/mo)	($/KW)	($/KW)	($/KW)	($/KWH)	($/KWH)	($/KWH)	($/KWH)	($/KWH)	($/KWH)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
AL-TOU										
Secondary	20.00	3.05	3.36	14.42	0.08934	0.05777	0.04369	0.08011	0.05053	0.04250
Primary	20.00	2.42	3.36	14.42	0.08359	0.05502	0.04089	0.07492	0.04691	0.03868
Transmission	20.00	1.02	1.34	9.07	0.08109	0.05337	0.03967	0.07267	0.04551	0.03752
A6-TOU										
Secondary	600.00	3.05	4.01	17.18						
Primary	600.00	2.42	4.01	17.18	0.08359	0.05502	0.04089	0.07492	0.04691	0.03868
Transmission	600.00	1.02	1.79	11.01	0.08109	0.05337	0.03967	0.07267	0.04551	0.03752

A.87-04-018, A.87-07-009 ALJ/RLW CACD/PAC/8/1

APPENDIX C
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ADOPTED RATES
SCHEDULES: PA-TOU, AO-TOU, AO6-TOU, DA-TOU, DU-TOU

Customer Class	Customer Charge ($/mo)	Max Demand ($/KW)	Winter On-Pk Demand ($/KW)	Summer On-Pk Demand ($/KW)	On-Pk Energy ($/KWH)	Semi-Pk Energy ($/KWH)	Off-Pk Energy ($/KWH)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
PA-TOU	8.00				0.18269		0.07506
AO-TOU	50.00	7.31	3.50	13.00	0.06979	0.04696	0.03448
AO6-TOU	250.00	7.31	4.17	15.49	0.06979	0.04696	0.03448
DA-TOU							
Baseline					0.10142		0.05071
Non-Baseline					0.22573		0.11286
DU-TOU							
Baseline					0.07006		0.03503
Non-Baseline					0.15594		0.07797

A. 87-04-018, A. 87-07-009 ALJ/RLW CACD/PAC/8/1

APPENDIX C
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ADOPTED RATES
SCHEDULES: AE-1, RTOU-1, RTOU-2

Customer Class	Customer Charge ($/mo)	On-Pk Demand ($/KW)	Semi-Pk Demand ($/KW)	Super-Pk Energy ($/KWH)	On-Pk Energy ($/KWH)	Semi-Pk Energy ($/KWH)	Off-Pk Energy ($/KWH)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
AE-1	600.00	13.75	0.50		8.29072	0.06733	0.03834
RTOU-1	600.00	13.75	0.50	0.94416	0.29585	0.06681	0.03810
RTOU-2	600.00	13.75	0.50	0.49416	0.13495	0.05975	0.03732

APPENDIX C
Page 6

ADOPTED RATES
SCHEDULE PA T-1

Customer Class	Customer Charge ($/mo)	On-Pk Demand ($/KW)	Semi-Pk Demand ($/KW)	On-Pk Energy ($/KWH)	Semi-Pk Energy ($/KWH)	Off-Pk Energy ($/KWH)
(A)	(B)	(C)	(D)	(E)	(F)	(G)
PA T-1	20.00		0.50	0.10417	0.07255	0.04113
Option A [1]		8.71				
Option B		7.65				
Option C		7.48				
Option D		7.80				
Option E		7.64				
Option F		7.31				

[1] Option A -- On-Pk Demand Charge is applied to contribution to monthly peak.
A. 87-04-018, A. 87-07-009 ALJ/RLW CACD/PAC/8/1

ELECTRIC DEPARTMENT
LIGHTING SERVICES
SUMMARY OF ADOPTED RATES
(J82)

LINE NO.	SERVICE DESCRIPTION	MONTHLY AVERAGE USAGE (KWHR)	CURRENT TOTAL RATE ($/Mth)	ADOPTED CHANGE BASE AMOUNT(1) ($/Mth)	ADOPTED CHANGE ECAC/AER AMOUNT(2) ($/Mth)	ADOPTED TOTAL RATE ($/Mth)	ADOPTED INCREASE (%)
		(a)	(b)	(c)	(d)	(e)	(f)
1.	SCHEDULE LS-1 (UTILITY-OWNED)						
2.	MERCURY VAPOR						
3.	CLASS A						
4.	175 W	75	12.99	-0.87	-0.44	11.68	-10.08
5.	250 W	104	15.34	-0.98	-0.61	13.75	-10.37
6.	400 W	164	22.72	-1.42	-0.96	20.34	-10.48
7.	700 W	279	35.70	-2.17	-1.63	31.90	-10.64
8.	CLASS C - 1-LAMP						
9.	175 W	75	23.40	-1.75	-0.44	21.21	-9.36
10.	250 W	104	26.21	-1.90	-0.61	23.70	-9.58
11.	400 W	164	33.96	-2.38	-0.96	30.62	-9.84
12.	CLASS C - 2-LAMP						
13.	175 W	150	35.67	-2.57	-0.88	32.22	-9.67
14.	400 W	328	55.65	-3.72	-1.92	50.01	-10.13
15.	REACTOR BALLAST REDUCTION						
16.	175 W	4	0.50	-0.03	-0.02	0.45	-10.00
17.	250 W	6	0.81	-0.05	-0.04	0.72	-11.11
18.	HPSV						
19.	CLASS A						
20.	70 W	30	7.61	-0.55	-0.18	6.88	-9.59
21.	100 W	42	9.16	-0.65	-0.25	8.26	-9.83
22.	150 W	61	11.14	-0.76	-0.36	10.02	-10.05
23.	200 W	88	14.43	-0.95	-0.51	12.97	-10.12
24.	250 W	112	16.99	-1.10	-0.65	15.24	-10.30
25.	400 W	170	23.64	-1.48	-0.99	21.17	-10.45
26.	1,000 W	395	49.34	-2.98	-2.31	44.05	-10.72
27.	CLASS B - 1-LAMP						
28.	70 W	30	8.32	-0.61	-0.18	7.53	-9.50
29.	100 W	42	9.76	-0.70	-0.25	8.81	-9.73
30.	150 W	61	11.89	-0.82	-0.36	10.71	-9.92
31.	200 W	88	15.18	-1.02	-0.51	13.65	-10.08
32.	250 W	112	17.74	-1.16	-0.65	15.93	-10.20
33.	400 W	170	24.43	-1.55	-0.99	21.89	-10.40
34.	1,000 W	395	50.42	-3.07	-2.31	45.04	-10.67

(1) (Col. b - (Col. a x $0.03608/kwhr present ECAC/AER)) x (-8.48%+ adopted base change)
(2) (Col. a x -$0.00584/kwhr adopted ECAC/AER change)

ELECTRIC DEPARTMENT
LIGHTING SERVICES
SUMMARY OF ADOPTED RATES

LINE NO.	SERVICE DESCRIPTION	MONTHLY AVERAGE USAGE (KWHR)	CURRENT TOTAL RATE ($/Mth)	ADOPTED CHANGE BASE AMOUNT(1) ($/Mth)	ADOPTED CHANGE ECAC/AER AMOUNT(2) ($/Mth)	ADOPTED TOTAL RATE ($/Mth)	ADOPTED INCREASE (%)
		(a)	(b)	(c)	(d)	(e)	(f)
1.	SCHEDULE LS-1 (UTILITY-OWNED)(CONTINUED)						
2.	CLASS B - 2-LAMP						
3.	70 w	60	14.80	-1.07	-0.35	13.38	-9.59
4.	100 w	84	17.79	-1.25	-0.49	16.05	-9.78
5.	150 w	122	21.91	-1.48	-0.71	19.72	-10.00
6.	200 w	176	28.50	-1.88	-1.03	25.59	-10.21
7.	250 w	224	33.53	-2.16	-1.31	30.06	-10.35
8.	400 w	340	46.99	-2.94	-1.99	42.06	-10.49
9.	1,000 w	790	98.69	-5.95	-4.61	88.13	-10.70
10.	CLASS C - 1-LAMP						
11.	70 w	30	18.85	-1.51	-0.18	17.16	-8.97
12.	100 w	42	20.46	-1.61	-0.25	18.60	-9.09
13.	150 w	61	23.05	-1.77	-0.36	20.92	-9.24
14.	200 w	88	26.34	-1.96	-0.51	23.87	-9.38
15.	250 w	112	28.89	-2.11	-0.65	26.13	-9.55
16.	400 w	170	36.05	-2.54	-0.99	32.52	-9.79
17.	1,000 w	395	67.05	-4.48	-2.31	60.26	-10.13
18.	CLASS C - 2-LAMP						
19.	70 w	60	25.57	-1.98	-0.35	23.24	-9.11
20.	100 w	84	28.90	-2.19	-0.49	26.22	-9.27
21.	150 w	122	33.29	-2.45	-0.71	30.13	-9.49
22.	200 w	176	39.86	-2.84	-1.03	35.99	-9.71
23.	250 w	224	44.89	-3.12	-1.31	40.46	-9.87
24.	400 w	340	59.37	-3.99	-1.99	53.39	-10.07
25.	1,000 w	790	116.07	-7.43	-4.61	104.03	-10.37
26.	LPSV						
27.	CLASS A						
28.	35 w	23	9.55	-0.74	-0.13	8.68	-9.11
29.	55 w	31	10.30	-0.78	-0.18	9.34	-9.32
30.	90 w	50	12.86	-0.94	-0.29	11.63	-9.56
31.	135 w	71	16.06	-1.14	-0.41	14.51	-9.65
32.	180 w	82	17.61	-1.24	-0.48	15.89	-9.77
33.	CLASS C - 1-LAMP						
34.	35 w	23	17.38	-1.40	-0.13	15.85	-8.80
35.	55 w	31	18.15	-1.44	-0.18	16.53	-8.93
36.	90 w	50	20.80	-1.61	-0.29	18.90	-9.13
37.	135 w	71	24.72	-1.88	-0.41	22.43	-9.26
38.	180 w	82	26.41	-1.99	-0.48	23.94	-9.35
39.	CLASS C - 2-LAMP						
40.	35 w	46	26.85	-2.14	-0.27	24.44	-8.98
41.	55 w	62	28.36	-2.22	-0.36	25.78	-9.10
42.	90 w	100	33.46	-2.53	-0.58	30.35	-9.29
43.	135 w	142	40.40	-2.99	-0.83	36.58	-9.46
44.	180 w	164	43.51	-3.19	-0.96	39.36	-9.54

(1) (Col. b - (Col. a x $0.03608/kwhr present ECAC/AER)) x (-8.484+ adopted base change)
(2) (Col. a x -$0.00584/kwhr adopted ECAC/AER change)

ELECTRIC DEPARTMENT
LIGHTING SERVICES
SUMMARY OF ADOPTED RATES

LINE NO.	SERVICE DESCRIPTION	MONTHLY AVERAGE USAGE (KWHR)	CURRENT TOTAL RATE ($/Mth)	ADOPTED CHANGE: BASE AMOUNT(1) ($/Mth)	ADOPTED CHANGE: ECAC/AER AMOUNT(2) ($/Mth)	ADOPTED TOTAL RATE ($/Mth)	ADOPTED INCREASE (%)
		(a)	(b)	(c)	(d)	(e)	(f)
1.	SCHEDULE LS-2 (CUSTOMER-OWNED)						
2.	MERCURY VAPOR						
3.	RATE A						
4.	175 w	75	7.57	-0.41	-0.44	6.72	-11.23
5.	250 w	104	10.67	-0.59	-0.61	9.47	-11.25
6.	400 w	164	16.70	-0.91	-0.96	14.83	-11.20
7.	700 w	279	27.82	-1.51	-1.63	24.68	-11.29
8.	1,000 w	394	39.03	-2.10	-2.30	34.63	-11.27
9.	RATE B						
10.	175 w	75	8.91	-0.53	-0.44	7.94	-10.89
11.	250 w	104	11.85	-0.69	-0.61	10.55	-10.97
12.	400 w	164	17.64	-0.99	-0.96	15.69	-11.05
13.	HPSV						
14.	RATE A						
15.	50 w	21	2.17	-0.12	-0.12	1.93	-11.06
16.	70 w	38	3.93	-0.22	-0.22	3.49	-11.20
17.	100 w	52	5.47	-0.30	-0.30	4.87	-10.97
18.	150 w	71	7.45	-0.41	-0.41	6.63	-11.01
19.	200 w	88	8.66	-0.47	-0.51	7.68	-11.32
20.	250 w	112	11.60	-0.64	-0.65	10.31	-11.12
21.	310 w	137	12.97	-0.68	-0.80	11.49	-11.41
22.	400 w	170	17.47	-0.96	-0.99	15.52	-11.16
23.	1,000 w	395	39.17	-2.11	-2.31	34.75	-11.28
24.	RATE B						
25.	50 w	21	3.52	-0.23	-0.12	3.17	-9.94
26.	70 w	38	5.17	-0.32	-0.22	4.63	-10.44
27.	100 w	52	6.84	-0.42	-0.30	6.12	-10.53
28.	150 w	71	8.87	-0.53	-0.41	7.93	-10.60
29.	200 w	88	9.99	-0.58	-0.51	8.90	-10.91
30.	250 w	112	13.09	-0.77	-0.65	11.67	-10.85
31.	310 w	137	14.30	-0.79	-0.80	12.71	-11.12
32.	400 w	170	18.95	-1.09	-0.99	16.87	-10.98
33.	1,000 w	395	41.32	-2.30	-2.31	36.71	-11.16
34.	REACTOR BALLAST REDUCTION						
35.	70 w	8	0.76	-0.04	-0.05	0.67	-11.84
36.	100 w	10	1.02	-0.06	-0.06	0.90	-11.76
37.	150 w	10	0.98	-0.05	-0.06	0.87	-11.22

(1) (Col. b - [Col. a x $0.03608/kwhr present ECAC/AER]) x (-8.48%+ adopted base change)
(2) (Col. a x -$0.00584/kwhr adopted ECAC/AER change)

ELECTRIC DEPARTMENT
LIGHTING SERVICES
SUMMARY OF ADOPTED RATES

LINE NO.	SERVICE DESCRIPTION	MONTHLY AVERAGE USAGE (KWHR)	CURRENT TOTAL RATE ($/Mth)	ADOPTED CHANGE: BASE AMOUNT(1) ($/Mth)	ADOPTED CHANGE: ECAC/AER AMOUNT(2) ($/Mth)	ADOPTED TOTAL RATE ($/Mth)	ADOPTED INCREASE (%)
		(a)	(b)	(c)	(d)	(e)	(f)
1.	SCHEDULE LS-2 (CUSTOMER-OWNED)(CONTINUED)						
2.	LPSV						
3.	RATE A						
4.	35 w	23	2.44	-0.14	-0.13	2.17	-11.07
5.	55 w	31	3.19	-0.18	-0.18	2.83	-11.29
6.	90 w	50	5.28	-0.29	-0.29	4.70	-10.98
7.	135 w	71	7.18	-0.39	-0.41	6.38	-11.14
8.	180 w	82	8.17	-0.44	-0.48	7.25	-11.26
9.	INCANDESCENT						
10.	RATE A						
11.	1,000 L	25	2.90	-0.17	-0.15	2.58	-11.03
12.	2,500 L	56	6.42	-0.37	-0.33	5.72	-10.90
13.	4,000 L	85	9.67	-0.56	-0.50	8.61	-10.96
14.	6,000 L	124	13.90	-0.80	-0.72	12.38	-10.94
15.	10,000 L	211	23.15	-1.32	-1.23	20.60	-11.02
16.	RATE B						
17.	4,000 L	85	11.38	-0.70	-0.50	10.18	-10.54
18.	6,000 L	124	15.68	-0.95	-0.72	14.01	-10.65
19.	SCHEDULE OL-1						
20.	MERCURY VAPOR						
21.	RATE A						
22.	175 w	71	12.85	-0.87	-0.41	11.57	-9.96
23.	400 w	164	24.93	-1.61	-0.96	22.36	-10.31
24.	HPSV						
25.	RATE A						
26.	100 w	42	9.22	-0.65	-0.25	8.32	-9.76
27.	150 w	61	11.33	-0.77	-0.36	10.20	-9.97
28.	250 w	112	17.22	-1.12	-0.65	15.45	-10.28
29.	400 w	170	23.94	-1.51	-0.99	21.44	-10.44
30.	1,000 w	395	49.84	-3.02	-2.31	44.51	-10.69
31.	RATE B						
32.	250 w	112	20.74	-1.42	-0.65	18.67	-9.98
33.	400 w	170	27.18	-1.78	-0.99	24.41	-10.19
34.	1,000 w	395	52.53	-3.25	-2.31	46.97	-10.58
35.	LPSV						
36.	RATE A						
37.	55 w	31	10.40	-0.79	-0.18	9.43	-9.33
38.	90 w	50	12.99	-0.95	-0.29	11.75	-9.55
39.	135 w	71	16.22	-1.16	-0.41	14.65	-9.68
40.	180 w	82	17.74	-1.25	-0.48	16.01	-9.75
41.	SCHEDULE DWL						
42.	50 w HPSV	21	3.38	-0.22	-0.12	3.04	-10.06
43.	100 w HPSV	42	5.90	-0.37	-0.25	5.28	-10.51
44.	100 w MERCURY	45	5.16	-0.30	-0.26	4.60	-10.85
			($/kwhr)	($/kwhr)	($/kwhr)	($/kwhr)	
45.	SCHEDULE LS-3(ENERGY ONLY)						
46.	ENERGY CHARGE		0.10474	-0.00582	-0.00584	0.09308	-11.13

(1) (Col. b - (Col. a x $0.03608/kwhr present ECAC/AER)) x (-8.48%+ adopted base change)
(2) (Col. a x -$0.00584/kwhr adopted ECAC/AER change)

ALJ/RLW/tcg

Decision ____________

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company, for Authority to Introduce a Mandatory L6-TOU Rate to Replace its Existing A6-TOU and AL-TOU Rates and to Revise Portions of its Existing Standby Tariffs. (1 902-E)	Application 87-04-018 (Filed April 10, 1987)
In the matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY for Authority to Revise its Energy Cost Adjustment Clause (ECAC) Rate, to Revise its Annual Energy Rate (AER), and to Revise its Electric Base Rates effective November 1, 1987 in accordance with the Electrical Revenue Adjustment Mechanism (ERAM) (U 902-E)	Application 87-07-009 (Filed July 2, 1987; amended August 20, 1987)

(Appearances are listed in Appendix A.)

OPINION

I. Summary

By this order we adopt San Diego Gas & Electric Company's (SDG&E's) Energy Cost Adjustment Clause (ECAC) forecast of fuel and purchased power expense for the period November 1, 1987 - October 31, 1988. The related ECAC rate changes combined with changes to the Annual Energy Rate (AER) and the Electric Revenue Adjustment Mechanism (ERAM) result in a total revenue decrease of $82.935 million.

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I. Summary

By this order we adopt San Diego Gas & Electric Company's (SDG&E's) Energy Cost Adjustment Clause (ECAC) forecast of fuel and purchased power expense for the period November 1, 1987 - October 31, 1988. The related ECAC rate changes, changes to the Annual Energy Rate (AER) and the Electric Revenue Adjustment Mechanism (ERAM), and changes to base rates and the Major Additions Adjustment Clause (MAAC) rates result in a total revenue decrease of $174.6 million. The revenue changes are shown on Appendix B.

We also adopt revised marginal costs for SDG&E based upon the company's cost study but adjust the company's figures in several respects as recommended by intervenors.[1]

After examining the revenue allocation that would result from strict application of an Equal Percentage of Marginal Cost (EPMC) method, we find that the EPMC method should be constrained so that each customer class receives a minimum 5.0% rate decrease. Although residential and agricultural revenues are below the EPMC allocation for their classes, we will lower all rates in the context of a substantial revenue decrease. We believe that SDG&E's rates must be restructured and moved towards marginal costs in a deliberate and careful manner. Our adopted revenue allocation makes significant movement towards the adopted marginal costs and allows time for the refinement of marginal cost studies in future proceedings.

The adopted rate design, i.e. rates within each customer class, relies heavily upon an agreement submitted after hearing. The major change is the unbundling of costs for SDG&E's large commercial and industrial customers served under Schedules AL-TOU, A6-TOU, and S. Similar to the rates adopted for the other major electric utilities in California, SDG&E's large commercial and industrial rates are further unbundled to provide for higher demand and standby charges and lower energy rates. We also adopt a customer charge for residential customers as proposed by the

1 The adopted marginal costs are to a large extent of only academic interest as our revenue allocation is constrained by the use of caps. The adopted marginal costs reflect our appraisal of the evidence on this record. However, we recognize that several novel ideas were introduced in this proceeding which should be examined in SDG&E's upcoming general rate case.

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After examining the revenue allocation that would result from strict application of an Equal Percentage of Marginal Cost (EPMC) method, we find that the EPMC method should be constrained so that no customer class receives a rate increase. Although residential and agricultural revenues are below the EPMC allocation for their classes, we will not increase any rates in the context of an overall revenue decrease. Instead, we will hold residential and agricultural rates at their present levels and will allocate the entire revenue decrease to the other customer classes whose revenues under present rates are significantly above their EPMC allocations. We believe that SDG&E's rates must be restructured and moved towards marginal costs in a deliberate and careful manner. Our adopted revenue allocation makes significant movement towards the adopted marginal costs while avoiding disruptive rate changes and allowing time for the refinement of marginal cost studies in future proceedings.

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Division of Ratepayer Advocates (DRA)[2] and a higher AD demand charge as proposed by SDG&E. The adopted rates are shown in Appendix C.

We also find that troubling questions have been raised about the level of SDG&E's costs and the Commission's movement towards recovery of these high costs in fixed charges. We expect to examine SDG&E's marginal and embedded costs in the company's upcoming general rate case.

II. Procedural Background

SDG&E has filed two separate applications. The first application, Application (A.) 87-04-018, is an extraordinary request to restructure the rates charged to SDG&E's large commercial and industrial customers without changing the collected revenues.[3] The second application, A.87-07-009, is the usual ECAC filing requesting the adoption of a new forecast of fuel and purchased power expense and the implementation of the resulting changed revenue requirement through revised ECAC rates.

Prehearing conferences were held on both applications. At these conferences, several intervenors asked for consolidation of the two applications so that they could address in one proceeding the impact of both applications on customer rates. The Administrative Law Judge (ALJ) granted this request and consolidated the ECAC forecast portion of A.87-07-009 with

2 The Public Staff Division has been renamed the Division of Ratepayer Advocates.

3 If A.87-04-018 had been approved as filed, the amount of revenues collected by SDG&E would have changed. Although SDG&E characterized the application as revenue neutral, the imposition of its proposed standby charges would have increased revenues.

and standby charges and lower energy rates. We also adopt a customer charge for residential customers as proposed by the Division of Ratepayer Advocates (DRA)[2] and a higher AD demand charge as proposed by SDG&E.

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ECAC forecast portion of A.87-07-009 with A.87-04-018. The reasonableness review portion of A.87-07-009 was kept separate.

Evidentiary hearings on the consolidated proceeding were held from September 21, 1987 to October 8, 1987. Testimony from members of the public was received on September 23, 1987. SDG&E, DRA, Utility Consumers' Action Network (UCAN), San Diego Energy Alliance (Alliance), Federal Executive Agencies (FEA), Hospital Council of San Diego and Imperial Counties on behalf of Cogeneration Hospitals (Hospitals), and San Diego Mineral Products Industry Coalition (MinPros) presented witnesses and sponsored expert testimony. The City of San Diego (City) actively participated through cross-examination. Concurrent briefs were filed by November 6, 1987.

III. ECAC Forecast of Fuel and Purchased Power Expense

A. Adopted Forecast

We adopt SDG&E's fuel and purchased power forecast as shown on Table 1.

TABLE 1

Purchased Energy	$310,936,600
Geothermal Energy	0
Nuclear Generation	25,207,700
Natural Gas	119,161,200
Distillate Oil	13,700
Residual Oil	1,750,000
Subtotal	$457,069,200
Distillate Writedown	254,700
Fuel Oil Inventory	1,750,000
Wheeling Expenses	9,980,100
EFI Adjustment	(5,461,400)
Net Losses on Sale of Oil	0
Total	$463,123,100*

*This total should be adjusted to reflect several changes acknowledged by SDG&E's witnesses at hearing. These changes are summarized in a October 9, 1987 letter of Don Garber, attorney for SDG&E, to the Administrative Law Judge. The changes, adjusted by the company's jurisdictional factor further increase the ECAC, AER, and ERAM reduction of $82.5 million to $82.935 million.

This forecast was submitted in the August 20, 1987 Amendment to A.87-07-009 and is based upon more recent data than DRA's forecast. The adopted forecast combined with the most recent updates on the ECAC and ERAM balancing accounts yields a total revenue decrease of $82.935 million as shown on Table 2.

TABLE 2

ECAC	-$109.6 million
AER	-$ 4.7 million
ERAM	$ 31.4 million
Total	-$ 82.9 million

B. <u>Residual/ECAC Issues</u>

Although SDG&E and PSD agreed on the amount of the revenue decrease, they continue to disagree over the ratemaking treatment of the capacity charge to be paid to Tucson-Alamito, revision of the AER to reflect the Commission's decision in the OII/OIR Gas Implementation proceeding, I.86-06-005, and the proper ratemaking treatment of fuel oil inventory.

1. Tucson-Alamito Capacity Charge

On June 30, 1987, SDG&E filed at the Federal Energy Regulatory Commission (FERC) a complaint to determine the rights and obligations of SDG&E and the Alamito Company,[4] under a purchased power agreement. SDG&E alleges in this complaint that the scheduling practices and requirements of Alamito have reduced the firm capacity available to SDG&E under the contract from 400 MW to 100 MW. Until this complaint is resolved by the FERC, SDG&E is withholding payment for 300 MW of capacity. Thus, SDG&E currently is paying Alamito for only 100 MW of firm capacity. However, SDG&E's ECAC forecast reflects payment for the full 400 MW of capacity to Alamito.

SDG&E believes that its forecast incorporating the full 400 MW capacity payment to Alamito is appropriate since the outcome of the FERC litigation is problematic. SDG&E submits that the probability and timing of FERC reforming the agreement from 400 MW to 100 MW is unknown. SDG&E points out that if it does win its case at FERC, then 92% of the dollar benefits from this victory will flow to the ratepayers while only 8% will flow to the shareholders. SDG&E believes that the purpose of this ECAC/AER split is to allocate benefits between ratepayers and shareholders and thereby to give utility management an additional incentive to

4 Tucson Electric Power Company controls the dispatch of power purchased from the Alamito Company. Thus, SDG&E's communications have been with Tucson personnel although Alamito is the responsible party.

lower energy costs.[5] For this reason, SDG&E opposes a recommendation of the City that the Alamito capacity payment should be given 100 percent ECAC balancing account treatment.

If SDG&E were to lose the FERC litigation, then SDG&E could be forced to pay Alamito the withheld 300 MW capacity payment. SDG&E argues that this later payment could result in a significant upward rate shock if SDG&E is not allowed to recover the full 400 MW payment through ECAC now.

The City, UCAN, and DRA all recommend that this forecast should reflect payment for the full 400 MW capacity to Alamito subject to 100% ECAC balancing account treatment. The City points out that without provision for balancing account treatment, SDG&E will recover in the AER about $5,863,299 for capacity costs that it is not currently paying. If the Commission does not desire to make 100% of the Alamito payment subject to balancing account treatment, then the City submits that SDG&E's AER expenses in the forecast period should be reduced by $5,863,200. UCAN points out that SDG&E will reap some of any benefit resulting from the FERC litigation since the company began withholding payment from Alamito on June 1, 1987 and the Commission will not be able to order balancing account treatment for this expense until December, 1987.

5 An electric utility's fuel and purchased power expense is recovered through an ECAC rate and an AER. Both the ECAC rate and the AER are based upon a forecast of the utility's fuel and purchased power expense over a one year period (the forecast period). The ECAC rate is subject to a balancing account and is adjusted to reflect recorded differences in actual expenses from the forecast of fuel and purchased power expense. The AER is not subject to a balancing account. The utility's shareholders absorb any difference in actual energy expense from the forecast expense underlying the AER. SDG&E recovers 92% of its fuel and purchased power expense through an ECAC rate and 8% through an AER. This 92%/8% "split" is based upon the amount of earnings fluctuation the Commission has determined that SDG&E can withstand.

We adopt the City's proposal for 100% ECAC balancing account treatment of the Alamito capacity payment. This procedure has been adopted on other occasions when the payments were substantial and the amounts were dependent upon the outcome of litigation. At this point in time we cannot predict what the outcome of the FERC litigation will be. If the full 400 MW payment is reflected without 100% balancing account treatment, then we would be compelling ratepayers to pay nonrefundable rates reflecting costs that SDG&E is not paying. If we recognize only the current 100 MW payment, then we would be exposing shareholders to the risk that SDG&E may lose the litigation and have to pay the withheld 300 MW charge to Alamito and then recover only 92% of that payment from ratepayers. Neither result is satisfactory. If we were to adhere to the ECAC/AER ratemaking approach, then we might recognize some intermediate level of capacity payment such as 250 MW. We elect instead to provide for 100% ECAC balancing account treatment to avoid speculation on the outcome of SDG&E's FERC complaint and to ensure that neither ratepayers or shareholders are unfairly penalized.

2. <u>OII/OIR Gas Implementation Decision</u>

SDG&E based its ECAC forecast upon then current rates for gas. SDG&E was fully aware that the gas charges would be changed in the pending OII/OIR Gas Implementation proceeding but expected the Commission to issue a decision implementing these changes before this ECAC application is decided. However, since the gas proceeding has fallen behind schedule, SDG&E now believes that the implementation of the revised gas rate structures may not occur before an ECAC decision is issued. Since the gas rates to be adopted by the Commission may differ substantially from the current rates, SDG&E proposes that it be allowed to file an advice letter modifying the adopted AER when the gas OII/OIR implementation results are final.

SDG&E argues that the AER mechanism was not intended to put either ratepayers or shareholders at risk for the unprecedented transitional problems now occurring in the gas industry. SDG&E submits that the Commission can easily avoid an inequitable result by allowing the company to file an advice letter revision reflecting the adopted utility electric generation gas charges which should be almost entirely fixed charges.

DRA opposes SDG&E's suggested advice letter procedure. DRA points out that once an AER is in place, the Commission has not allowed changes to reflect increases or decreases in fuel costs with the exception of a nuclear plant entering service. DRA maintains that the parties strive to make their best estimates of fuel costs and then live with the results until the next AER revision date. DRA contends that there is no reason to single out gas expenses for unique treatment. While current gas costs may be difficult to predict, DRA argues that other expenses such as purchased power prices are equally difficult to predict.

DRA further argues that SDG&E is selective in its request for special ratemaking treatment. DRA observes that when the Commission first allowed SDG&E to purchase spot gas and to transport that gas, the company did not ask that its then effective AER be reduced to reflect lowered gas expense.

To the extent we can recognize changed gas prices for SDG&E in this ECAC application, we will do so. However, we are unwilling to modify the AER procedure to allow for advice letter revision during the forecast period. The main purpose of the AER is to fix the company's expected fuel and purchased power expense at a single point in time and to have the shareholders absorb any fluctuations from the adopted level. Approval of an advice letter revision would substantially undercut the purpose and the effect of the AER. And as pointed out by DRA, there is no assurance that the company would make equal efforts to file advice letters reducing the AER.

3. Fuel Oil Inventory

DRA has proposed that the ratemaking treatment of the carrying cost of fuel oil inventory should be changed so that the company would receive a "lump sum" for this expense which would not be adjusted to reflect actual expenses in the forecast period. Essentially, DRA is recommending that SDG&E recover its entire fuel oil inventory carrying cost through the AER.

DRA asserts that this removal of balancing account treatment for fuel oil inventory carrying cost is consistent with the Commission's recent statements that utilities should not be insulated from the results of their management decisions by balancing accounts but should experience firsthand the gains and the losses resulting from their decisions.

SDG&E responds that this "lump sum" approach will create perverse incentives for utility management. SDG&E argues that to treat one energy expense differently than other related energy expenses would create incentives for management to focus on inventory costs more than other energy costs.

SDG&E further responds that, if adopted, the "lump sum" proposal will not simplify the Commission's reasonableness review, as contended by DRA. SDG&E maintains that the Commission still will have to closely review the relationship between inventory levels, oil burns, and shortage costs.

Finally, SDG&E asserts that the existing ECAC/AER procedure gives it an adequate incentive to keep all energy costs, including the carrying cost of fuel oil inventory, as low as possible consistent with the provision of reliable service.

We decline to adopt PSD's "lump sum" approach for fuel oil inventory. We find no explanation as to why this particular energy expense should be segregated from other expenses and given different treatment. The rationale offered by DRA could be applied to other energy expenses, not just to the carrying cost of fuel oil inventory. Yet DRA does not explain why only fuel oil inventory

SDG&E has calculated marginal customer costs based on actual work orders from recent installations. SDG&E recognizes that the implementation of these calculated customer costs through EPMC could result in a disproportionate impact on residential customers. SDG&E stands by its cost study and believes that the EPMC method can be constrained through the use of caps, such as the minimum 2.5% decrease that SDG&E has proposed. SDG&E urges the Commission to determine the most accurate marginal costs and then to make the necessary pragmatic adjustments in the revenue allocation.

1. Marginal Energy Costs

SDG&E states that there is no meaningful disagreement on marginal energy costs. SDG&E has used the QFs in/QFs out methodology used and adopted in last year's ECAC and the 1986 Test Year General Rate Case.

2. Marginal Capacity Costs

SDG&E asserts that it and DRA have relied upon estimates of capacity costs provided by the Commission in the 1986 ECAC (D.87-01-051). SDG&E also states that it has no objection to the refinements proposed by FEA and the Alliance which more accurately calculate the marginal capacity costs of each customer class given unit marginal capacity costs.[7]

3. Marginal Customer Costs

SDG&E states that unlike prior Commission proceedings there is an extensive record on marginal customer costs. SDG&E

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7 SDG&E and DRA allocated capacity costs among customer classes by converting the dollar per kilowatt capacity costs into cents per kilowatthour by dividing the allocated capacity costs by the total hours in the time period. The time period costs then were determined by multiplying the cents per kilowatthour figure by kilowatthours consumed by the class in the time period. FEA and the Alliance simply multiply marginal cost per kilowatt by the kilowatt demand for each class.

believes that it has submitted a detailed work order study on the costs of providing access to the system to an additional customer.

SDG&E asserts that these costs consist of some portion of the equipment between the substation and the customer. A convenient analytic break is the final line transformer. SDG&E states the equipment from and including the transformer to the customer is dedicated to specific customers and thereby may be directly assigned to a customer class. This portion of the system is referred to as TSM or Transformer, Service drop and Meter. The equipment from the high side of the transformer to the substation may serve more than one customer class and is considered part of the common distribution system.

SDG&E asserts that unlike DRA it has included in its TSM estimate all costs from the high side of the transformer through the secondary system to the service drop and to the meter. SDG&E's estimates are based upon actual work orders and include the transformer and associated equipment, labor and transportation, the secondary connection to the transformer, the secondary cable and conduit, the secondary handhole and connections to the secondary and service cables, the service cable and conduit, and the meter material cost, meter testing and associated labor and transportation.

SDG&E's TSM estimates are based upon actual work orders obtained from its operating districts showing recent new customer installations. To estimate the cost of hooking up a new residential customer in single-family detached homes, SDG&E reviewed work orders for 228 customers judged to be representative of the residential class. A similar process was followed for each customer class with the exception of large TOU and agricultural classes for which no typical recent new customer installations could be found.

SDG&E states that its methodology and the empirical data are not questioned by any party. According to SDG&E, the only and not purchased power or nuclear production or gas expenses should receive "lump sum" treatment. We agree with SDG&E that the isolated treatment of a single energy cost could create perverse incentives for utility management. This was one reason why we revised our original ECAC/AER procedure which did not result in the uniform treatment of all energy expenses. We will not retrace our steps and return to a procedure equivalent to the placement of fuel oil inventory carrying cost in the AER.[6]

IV. Marginal Costs

All parties agree that the goal of the Commission is to adopt marginal cost-based rates. However, the parties do not agree on what SDG&E's marginal costs are or the extent to which SDG&E's rates should be based upon its marginal costs.

A. SDG&E's Proposed Marginal Costs

SDG&E's marginal cost witness J. S. Parsons explained that there is an established hierarchy of marginal cost components: energy, generating demand, transmission demand, distribution demand, and customer cost. Parsons testified that the variation among customer classes increases going down this hierarchy as the costs get closer to the individual customer service. Thus, while the energy component will not vary much among customers, the individual customer costs can be significantly different. Parsons stated that the current focus of the Commission and consequently of SDG&E is on the further definition of marginal customer costs.

6 If DRA believes that the utility should accept more of the risks and the benefits of its fuel and purchased power cost management, then a straightforward approach would be to recommend an increase of the AER percentage. This approach would treat all energy expenses in a consistent manner.

criticism is of the results. However, SDG&E maintains that the parties have based their criticisms upon invalid comparisons.

SDG&E states that the higher cost estimates it has calculated for "meters" and "services" are not surprising since the estimates used last year were only nominally based upon the same costs. SDG&E points out that many actual costs were not included in last year's estimates. The current estimates of costs are based upon the actual work orders and include much more than the FERC account definitions of meters and service drops which DRA relies upon.

SDG&E objects to DRA's primary recommendation that the Commission use DRA's customer cost estimates for Southern California Edison Company (SCE) as a proxy. SDG&E points out that DRA has presumed that the SDG&E and the SCE systems must be similar without making any study of the actual equipment used by the two electric distribution systems. DRA's witness on marginal costs acknowledged that he did not know if the SDG&E and SCE systems use different types of transformers, operate at different primary voltage levels, and employ different designed maximum voltage drops.

SDG&E submits that the burden is upon DRA to show that SDG&E and SCE incur the same, or very close to the same, costs. The burden is not upon SDG&E to show otherwise. Until DRA justifies the use of SCE as a surrogate, SDG&E maintains that the DRA primary recommendation must be rejected.

SDG&E also argues that DRA's secondary recommendation should be rejected. DRA recognized that the Commission might prefer not to use estimates derived for SCE as a proxy for SDG&E estimates and recommended that the Commission carry over the customer cost estimates adopted in last year's ECAC decision. However, SDG&E observes that those estimates include the cost of meters and service drops but exclude transformers. SDG&E also points out that even though DRA's secondary recommendation excludes transformer cost, it is higher than the primary recommendation which consists 70% of transformer costs. SDG&E submits that this discrepancy between DRA's primary and secondary recommendations shows that DRA's recommendations are result-oriented rather than accurate marginal cost estimations.

Apart from TSM estimates, SDG&E has allocated some portion of the common distribution system between the high side of the final line transformer and the substation to marginal customer costs. DRA has allocated no common distribution costs to marginal customer costs.

SDG&E allocated to customer costs 25% of the energized equipment and 50% of the non-energized equipment of the common distribution system. These allocation percentages are SDG&E's best estimates of the appropriate allocation of common distribution cost between demand and customer. While these percentages are admittedly round numbers, SDG&E argues that they are demonstrably better than DRA's estimate of zero.

B. DRA Proposed Marginal Costs

DRA argues that the Commission should not adopt SDG&E's marginal customer costs because under the EPMC method they would increase residential rates by 17% and would decrease large commercial and industrial rates by about 25%. DRA urges the Commission not to adopt a marginal cost study that would result in such drastic revenue allocation changes without very good evidence.

DRA contends that the evidence of marginal customer costs offered by SDG&E is suspect because the numbers are much higher than the estimates adopted last year and the marginal costs DRA has estimated for SCE. According to DRA, a comparison of TSM costs in FERC Accounts 368, 369, and 370 for SDG&E and SCE shows that SDG&E's estimated customer costs are much higher than the estimates for SCE. DRA also observes that the difference in SDG&E and SCE marginal customer costs is peculiar since the recorded rate base costs for these same FERC accounts are nearly the same for the two utilities.

Until the differences between the two utilities are explained, DRA maintains that the Commission should not adopt SDG&E's customer costs because of the impact these estimates would have on revenue allocation. DRA recommends instead that the Commission use as a proxy for SDG&E the customer cost estimates that DRA has derived for SCE. Alternatively, DRA states that the Commission could use the same customer costs adopted in last year's ECAC.

C. UCAN's Proposed Marginal Costs

UCAN recommends that DRA's TSM estimates for marginal customer costs should be adopted by the Commission. UCAN further recommends that incremental customer costs should be reduced by 29% in estimating marginal customer costs.

UCAN states that SDG&E's estimates of new customer costs appears significantly overstated. UCAN points to DRA's comparison of SDG&E and SCE estimates of customer costs by FERC account as good reason to doubt SDG&E's marginal customer costs. Before the Commission should approve SDG&E's customer costs, UCAN believes that a cost review of SDG&E's entire distribution system should be undertaken.

UCAN also offers several refinements to the marginal costs calculated by SDG&E and DRA. First, UCAN states that incremental customer costs should be reduced by 29%. UCAN believes this is appropriate because only new customers should pay the incremental costs of access to SDG&E's system. UCAN believes that existing customers should not be required to pay incremental costs but instead should be charged with the decremental cost of their access equipment. UCAN has derived an incremental/decremental method which imputes an incremental charge for new customers and a decremental charge for existing customers. The result of this method is to lower the total revenue requirement for all customer costs by 29%.

UCAN also recommends that the marginal generation capacity cost should be increased by 15% to reflect the utility's maintenance of an adequate reserve margin to provide reliable service to customers. Since SDG&E currently maintains a 15% reserve margin, UCAN proposes that the generation capacity costs should be multiplied by 1.15.

UCAN further points out that customer classes impose different requirements on the utility generation system and have different reliability needs. For example, baseload customers will impose greater reserve requirements on the system than will customers with more peaked load shapes. Also, residential customers may have a lower value for reliability than do commercial and industrial customers. UCAN believes that these matters should be given further study and consideration in marginal cost calculations before full EPMC is implemented by the Commission.

D. FEA Proposed Marginal Costs

FEA would allocate capacity costs among customer classes in a different manner than SDG&E and DRA have allocated them. FEA states that the correct way to allocate capacity costs is allocate them based upon customer class demands and not by customer class kilowatthours. FEA points out that SDG&E agrees that FEA's method for allocating capacity costs is an improvement of the method used by both the company and DRA in this ECAC proceeding.

FEA further recommends that SDG&E's customer costs should be adopted by the Commission. FEA believes that SDG&E's customer costs are superior since they are based upon a detailed analysis of SDG&E's system, while DRA's costs are based upon costs derived for SCE. Also, FEA points out that DRA's costs ignore common distribution costs, some of which FEA believes are properly included as customer costs.

In summary, FEA recommends adoption of DRA energy costs, SDG&E customer costs, and the FEA capacity costs.

E. Alliance Proposed Marginal Costs

The Alliance used DRA's customer costs as a conservative estimate of TSM costs. However, the Alliance includes SDG&E's allocation of common distribution costs in customer costs as the Alliance believes they are not duplicative of other customer costs and are properly assignable to a customer class.

The Alliance also recommends the same capacity allocation method used by FEA.

F. Adopted Marginal Costs

We will adopt SDG&E's marginal costs modified in several respects as recommended by intervenors. First, we adopt UCAN's incremental/decremental method for reducing the customer cost revenue requirement by 29%. Second, we adopt UCAN's proposal to multiply generation costs by 1.15 to reflect SDG&E's maintenance of a 15% reserve margin. Finally, we adopt the capacity allocation method recommended by FEA and the Alliance.

The concerns of DRA and other parties regarding the disparity between marginal costs by FERC account for SDG&E and SCE are not sufficient reason to reject SDG&E's marginal cost study. SDG&E's study is the only one submitted on this record which purports to estimate SDG&E's marginal costs. The critics of SDG&E's marginal cost estimates are concerned about the resulting revenue allocation under a full EPMC method. Any doubts one may have about the validity of the adopted marginal costs can be considered when the revenue allocation among customer classes is made. In other words, the results of the adopted marginal cost study can be mitigated by the use of caps and other constraints on a full EPMC allocation. Thus, the results of applying a particular marginal cost study are not a good reason to reject the study itself. A marginal cost study should be evaluated by the manner in which costs are assigned to customer classes and the estimation of those costs. We find that SDG&E's marginal cost study is the best evidence on this record of the marginal costs for its system. SDG&E's assignment of costs and estimation from actual work orders is clearly superior to the DRA's SCE proxy and the marginal costs adopted in last year's ECAC proceeding.

The three modifications to SDG&E's marginal costs that we adopt all improve the accuracy of cost estimates or the allocation among the customer classes. UCAN's incremental/decremental adjustment to customer costs is a more accurate estimation of costs imposed by existing and new customers. UCAN's 1.15 multiplier of generation or production costs also better reflects the utility's cost of maintaining a reserve margin. And the FEA/Alliance capacity allocation method allocates capacity costs among the customer classes based upon customer demand rather than energy consumed. FEA and the Alliance have shown that their methodology results in more precise allocations of capacity costs.

We expect that SDG&E's marginal costs will be examined more fully in the upcoming general rate case. The marginal costs we adopt here reflect the best evidence on this record. They are not intended to be a definitive statement of how SDG&E's marginal costs should be calculated or what they ideally should be. The marginal cost revenues are shown on Table 3 with the adopted revenue allocation.

V. Revenue Allocation

Having taken the bold step of adopting a new set of marginal costs for SDG&E, we now consider the need to constrain a full EPMC revenue allocation based upon the adopted marginal costs. If unconstrained, a full EPMC revenue allocation would result in large reductions to all customer classes apart from the residential class and the agricultural class which would receive increases as shown on Table 3. We will adopt a cap of no rate increases in the context of a substantial revenue decrease.[8] This cap eliminates the problem of explaining a rate increase to residential customers when overall revenues are decreased. At the same time, it allows substantial movement of the other customer classes towards marginal costs as the entire decrease is allocated to those classes. The "No Rate Increase" allocation also is shown on Table 3.

8 SDG&E and DRA recommended caps of a minimum 2.5% decrease for all classes. This minimum 2.5% decrease may be adopted if the total revenue decrease is substantially increased due to reductions in SDG&E's base rates. FEA and the Alliance recommended caps of 10.0% and 4.5% increases for the residential class. UCAN proposed a cap of 1% less than the system average decrease. The Hospitals recommended a no rate increase cap.

We also adopt UCAN's proposal that the reserve requirements and the reliability needs based upon value of service for the different customer classes should be studied in the 1989 TY General Rate Case. Such studies will allow for greater differentiation of capacity values and greater unbundling.

V. Revenue Allocation

Having taken the bold step of adopting a new set of marginal costs for SDG&E, we now consider the need to constrain a full EPMC revenue allocation based upon the adopted marginal costs. If unconstrained, a full EPMC revenue allocation would result in large reductions to all customer classes apart from the residential class and the agricultural class which would receive increases as shown in Appendix C. We will adopt a cap of a minimum 5.0% rate decrease for all customer classes. This cap ensures that all customers will receive a rate decrease when overall revenues are decreased. At the same time, it allows substantial movement of the customer classes towards marginal costs. The revenue allocation also is shown in Appendix C.

SDG&E also proposes to cap the revenue decrease to Schedule AD to 2.5%. Under a full EPMC revenue allocation, the AD customers would receive a 21.3% decrease. SDG&E points out that this schedule for general service demand-metered customers, which has no time-of-use rates, was closed by the Commission in last year's ECAC decision, D.87-01-051. To encourage the remaining customers on Schedule AD to migrate to time-of-use schedules, SDG&E would constrain the application of full EPMC to prevent a large reduction in the AD customer's average rate. SDG&E observes that this year only 44 customers out of some 8,000 have chosen to move to Schedule AL-TOU. SDG&E believes that a greater incentive to migrate is needed.

VI. Rate Design

Through A.87-04-018 SDG&E has asked the Commission to make three major changes to the rate schedules for its large commercial and industrial customers. First, SDG&E has proposed what it believes are unbundled, cost-based rates for the large commercial and industrial class. Second, SDG&E has proposed that its tariffs for standby and interruptible standby service furnished to self-generators be revised so that the company will recover the cost of maintaining capacity to serve customers with self-generation facilities. Third, SDG&E seeks to modify its PG-QF (Parallel Generation-Cogeneration or Power Production) tariff to limit the schedule to new customers who are not demand metered and whose demands are 20 kw or less. This change is intended to close the PG-QF schedule to new demand-metered commercial and industrial customers with relatively large loads (20 to 500 kw).

SDG&E states it has requested these changes so that its rates will recover capacity costs in capacity charges and will recover energy costs in energy charges. SDG&E asserts that the existing rate structure, in which capacity costs are recovered in energy charges, makes misallocation of resources a certainty and provides encouragement for inefficient energy generation. SDG&E claims that the present AL-TOU and A6-TOU schedules force large commercial and industrial customers with high load factors to subsidize commercial and industrial customers with low load factors.

SDG&E submits that there are important reasons for the Commission to act now in reforming the rate structure. First, SDG&E states high-load factor customers will continue to shift to self generation as they recognize that they are paying energy rates that recover not only the marginal costs of energy and capacity incurred by SDG&E to serve them, but also the cost of subsidizing other commercial and industrial customers. Second, SDG&E maintains that customers are making economic decisions based upon a rate structure that does not properly reflect SDG&E's cost of service.

To facilitate rapid reformation of the commercial and industrial rate structure, SDG&E entered into an agreement with DRA, the Alliance, the FEA, the Hospitals[9], and the MinPros with respect to most of the major issues concerning the proposed industrial rate structure. The other parties, UCAN and the City, were aware of this agreement but chose not to participate. The agreement has been identified as late-filed Exhibit 69 and was received by the Administrative Law Judge on November 9, 1987.

The principal areas on which agreement has been reached are as follows:

<u>Retail Schedule</u>

> Customer charges should be $20 for customers served on Schedule AL-TOU and $600 for customers served on Schedule A6-TOU.
>
> A non-coincident maximum demand charge ratchet should be employed instead of a contract demand charge.
>
> The level of the maximum demand charge should be differentiated by voltage levels with

9 The Hospitals support the agreement with one exception. The Hospitals state that the primary and the secondary on-peak demand charges should not be the same. The Hospitals suggest that the primary on-peak demand charge could be lowered to 50% between the secondary and transmission levels. The ALJ agrees that the primary and secondary rates should be differentiated but is reluctant to adjust the stipulated figures without comments from the other signatories to the agreement. The ALJ quite frankly does not know whether the other parties would regard the Hospitals' proposal as what Alliance witness Father Joe Carroll described as a venial sin or a mortal sin. Therefore, the parties should comment on the Hospitals' suggestion and propose alternative adjustments of the primary on-peak demand charge as exceptions to the ALJ proposed decision with the understanding that alternatives not related in some manner to the evidentiary record will not be blessed.

secondary defined as under 2KV, primary as 2KV to 24.99KV, and transmission as above 25KV.

An on-peak demand charge should be imposed without a ratchet. Separate charges should be established for the summer and winter periods.

The on-peak demand charge should be applied during the summer and winter periods as they are currently defined in Schedules AL-TOU and A6-TOU.

The new charges, excluding service and standby charges, should be subject to a rate limiter of 16 cents/kwhr.

The optional time-of-use schedules, AO-TOU and AO6-TOU, should be closed to new customers effective July 1, 1988.

<u>Standby Schedule</u>

All waivers on the existing standby tariff should be eliminated.

A separate standby charge based on the non-coincident demand charge should be applied in addition to the rates on the new schedules.

The regular retail schedule non-coincident maximum demand charge should be reduced by an amount not to exceed the contracted standby amount whenever the customer's generator is not operated.

A rate limiter applicable to the monthly charges billed at the on-peak demand charge and on-peak energy rates should be established for customers taking standby service.

A credit should be made for distribution payments from cogenerators.

Scheduled maintenance should not be subject to on-peak demand charges provided that the maintenance schedule has been agreed to by the utility.

There are four significant areas on which agreement was not reached.

> The specific maximum demand charge and ratchet level that should be imposed; agreement was reached only on the upper and lower bounds of these charges.
>
> The level of the winter standby on-peak demand and energy rate limiter.
>
> The level of the distribution payment credit on the standby schedule.
>
> The period for which Schedule PG-QF should remain open. (All parties agreed the schedule should be closed, but urged that closure be deferred for periods ranging from six months (SDG&E) to two years (the other parties).)

We adopt the agreement submitted as late-filed Exhibit 69. We recognize that both SDG&E and the other parties have made important sacrifices to achieve this compromise.[10] We now turn to the remaining areas of disagreement on the commercial and industrial rate structure.

A. <u>The Non-Coincident Demand Charge</u>

The parties agree that a non-coincident demand charge should be imposed. They disagree on the appropriate level of this charge. SDG&E proposes a charge of $4.05 per kw of demand at the secondary level, $3.22 per kw at the primary level, and $1.35 per kw at the transmission level. SDG&E states that its proposed charges are derived from the company's marginal costs of distribution as presented in the NOI for the 1989 General Rate Case. For example, the NOI distribution demand figure of $4.28

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10 SDG&E has withdrawn from this proceeding its concept of a contract demand charge which SDG&E believed would have given commercial and industrial customers an important element of control over their demand charges.

secondary was deflated by SDG&E to arrive at a 1988 level of $4.05. SDG&E further observes that the $4.05 is a compromise as the marginal cost of distribution is estimated at $7.69 per kw. Thus, SDG&E points out that its proposed charge would not recover $3.64 per kw of fixed cost.

The other parties propose charges of $3.17 per kw (secondary), $2.52 per kw (primary), and $1.06 per kw (transmission). The Alliance points out that SDG&E's original concept of a contract demand charge would have been phased in over a twenty-four month period, beginning with a $2 per kw charge and ending with a charge of $6.85 per kw. The Alliance contested the basis for the $6.85 per kw charge and opposed its adoption before the full development of marginal cost studies in SDG&E's upcoming general rate case. The Alliance urges the Commission to move cautiously until it does review SDG&E's costs in the general rate case. The Alliance points out that its proposed $3.17 charge exceeds SDG&E's original proposal of a $2.00 contract demand charge for the first twelve months of the phase-in period.

The Hospitals state that approval of the $3.17 maximum demand charge is the largest step towards unbundled rates which should be undertaken at this time. The Hospitals argue that the Commission's adoption of the higher charges proposed by SDG&E may result in the Commission having to "undo" the adopted rate structure in the upcoming general rate case. The Hospitals submit that the level of charges proposed by all parties other than SDG&E is similar to the levels adopted by the Commission for PG&E and suggested for adoption by SCE and DRA in SCE's pending general rate case.

We will adopt the non-coincident demand charges of $3.17 per kw (secondary), $2.52 per kw (primary), and $1.06 per kw (transmission). We adopt the lower set of demand charges proposed by all parties other than SDG&E because we prefer to move gradually towards the complete recovery of SDG&E's estimated fixed costs in fixed charges. These costs will be more closely examined in the general rate case. We will not leap to SDG&E's higher charges until we have looked at the underlying costs in the general rate case.

SDG&E and the other parties to the agreement also disagree as to the ratchet to be applied to the non-coincident demand charge. The purpose of a ratchet in the ratemaking context is "to improve the price signal to seasonal and intermittent customers." (Prepared Testimony of Paul Clanon, Exhibit 64, page 4-7.) SDG&E has proposed a ratchet of 75% while the other parties propose a ratchet of 50%.

SDG&E argues that a 50% ratchet will provide only token recovery of cost from intermittent customers. SDG&E originally proposed a 100% ratchet in its contract load charge but in the spirit of compromise has lowered its recommended ratchet to 75%. Below the level of 75%, SDG&E believes that the responsibility for the recovery of marginal distribution costs is unfairly shifted from intermittent customers, who created these costs, to other customers.

As noted by the Alliance, the record does not address the specific issue of a 50% ratchet vs a 75% ratchet. Lacking any evidence on this issue, we adopt the more conservative ratchet of 50% to be consistent with our stated goal of deliberate and careful movement towards unbundled rates.

B. The Winter Standby Rate Limiter

In the agreement, all parties have agreed that a standby rate limiter of $0.67 per kwh should be applied to on-peak demand and energy charges for the summer period. SDG&E believes this same $0.67 limiter should apply during the winter period. The other parties to the agreement propose a lower winter standby rate limiter of $0.26 per kwh.

SDG&E agrees in principle that a winter limiter is appropriate. However, SDG&E believes that insufficient study has been done to arrive at a specific winter level.

The Alliance states that all parties have recognized in their rate designs that SDG&E is a summer peaking utility and have allocated greater costs to the summer period than to the winter period. For example, the summer on-peak demand charges for the summer are significantly higher than the winter on-peak demand charges. The Alliance submits that to ignore this seasonal costing relationship would be contrary to cost-based rates and price signals.

We agree with the Alliance that since the adopted rate design appropriately differentiates between SDG&E's cost of service during the summer and winter seasons, the standby rate limiters should reflect a seasonal difference. We adopt the lower winter standby rate limiter of $0.26 per kwh.

C. Credit for Contributions to Distribution Facilities

In some instances, SDG&E's cogeneration customers pay for a portion of their distribution system. These contributions, made under Rule 21, are intended to cover installation and O&M costs not normally incurred by the utility. This practice then ensures that a customer's special requirements are met by that customer rather than borne by the customer body as a whole. The cogenerators have asked that they be given a credit against their noncoincident demand charges on the basis of their facilities payments. Since the noncoincident demand charges are intended to collect normal distribution costs, and the cost of the additional special facilities serving cogenerators is excluded, a credit would generally be improper. However, SDG&E recognizes that in rare cases a customer also may pay for a portion of its normal facilities as a part of a special fee. In this event, SDG&E is willing to recognize a credit of $0.10/kw.

The Alliance states that all other parties to the agreement have agreed that a $0.50 credit is fully supportable. The Alliance points out that a standby customer under Rule 15 is required to pay for 100 percent of the required facilities. In contrast, full requirements customers receive free allowances towards the same facilities. Since the noncoincident demand charges are designed to pay for distribution-related costs, standby customers could be paying twice for facilities already paid for under Rule 15. The Alliance points out that a credit of $1.00/kw has been adopted for PG&E. The Alliance believes that the $0.50 credit is conservative and should be selected over SDG&E's token amount of $0.10/kw.

We will adopt a credit of $0.50/kw. Using the PG&E credit of $1.00/kw as a reference, the $0.50 credit appears more reasonable. We also note testimony by the Alliance's witness on standby rates that he has calculated credits of about $0.70/kw for two San Diego facilities.

D. <u>Closing Schedule PG-QF</u>

SDG&E and DRA agree that Schedule PG-QF is a "giveaway" which "should go away" because "netting of energy is a very bad idea." However, they disagree as to how long the schedule should remain open. SDG&E urges that PG-QF should be closed within six months. DRA and other parties to the agreement recommend closure in two years.

Schedule PG-QF was instituted for facilities with output of 100 kw or less. This schedule allows small cogeneration systems to produce thermal loads at times when their electric loads are less than the output of their systems. The cogenerator may credit the excess electricity produced at these times against consumption during other periods when the site's electric load exceeds the power-generating capacity.

SDG&E states that it filed Advice Letter 701-E on March 10, 1987 requesting revision of PG-QF. Thus, SDG&E maintains that if the new commercial and industrial rates become effective on January 1, 1988, and PG-QF is closed six months thereafter, customers will have had at least fifteen months to bring new cogeneration projects on-line. SDG&E submits that to allow the schedule to remain open for a longer period will simply encourage developers to sell as many new projects as possible before the curtain falls.

The Alliance argues that the longer period of two years should be allowed because there are several projects under development which could be affected by closure of the schedule in a shorter time. The Alliance asserts that the development and the implementation of small cogeneration systems can take as long as two years.

We are sympathetic to the needs of the small cogeneration industry but believe that a period of one year should be sufficient to bring existing projects under development on-line. While SDG&E's advice letter filing was not an official pronouncement by the Commission, it was sufficient notice that closure of the schedule would be pursued by the utility. We are not willing to hold this schedule open for two years given the agreement by SDG&E and DRA that the schedule's energy netting provision is a bad idea which should go away as soon as possible. We believe a one year period gives adequate notice of the impending tariff change to customers and to developers.

We also approve the request of all parties that Schedule PG-QF apply to third party situations.

E. ECAC Rate Design Issues

Most of this consolidated proceeding was devoted to the extraordinary rate restructuring proposed in A.87-04-018 for the large commercial and industrial customers. There are two remaining rate design issues[11] raised in the ECAC A.87-07-009 regarding imposition of a residential customer charge and an increase in the non-coincident demand charge for Schedule AD customers.

1. Residential Customer Charge

DRA recommends that the current residential minimum bill of $0.16 per day be replaced with a monthly customer charge of $4.80 per month. SDG&E supported this recommendation.

DRA states that cost of service pricing is important to send proper price signals to customers, even if those customers have no alternative to buying electricity from SDG&E. DRA believes that the residential class should join the movement towards cost-based rates. DRA also observes that its proposed $4.80 monthly charge is well below either embedded or marginal costs.

SDG&E states that a customer charge is preferable to a minimum bill because it sends a more accurate price signal to the customer. Unlike a minimum bill, the customer charge applies uniformly to all customers regardless of usage and therefore more accurately reflects marginal costs imposed by each customer regardless of usage. While some low usage customers may see their bills increase because of a customer charge, SDG&E maintains that other customers will see a decrease because the customer charge would reduce the energy rate.

UCAN strongly opposes the proposed residential customer charge. UCAN asserts that a customer charge based upon incremental costs would overcharge existing customers whose true marginal costs are much lower. UCAN further argues that customer costs are not uniform among residential customers. Finally, UCAN contends that residential customers that use more energy will be subsidized by customers with lower energy demands if a residential customer

11 DRA agrees with SDG&E's proposal to raise the Schedule A customer charge from $2.20 per month to $5.00 per month.

charge is imposed. UCAN suggests that a moderate increase in the minimum bill is preferable if mandatory collection of additional customer costs is deemed necessary.

The City also opposes the DRA proposed residential customer charge. The City generally opposes the concept of guaranteeing to SDG&E more revenue in fixed charges. If a residential customer charge is approved, the City states the revenue from this charge must be included in the baseline energy rate calculation, as affirmed by DRA's witness.

We do not doubt that more refined customer charges could be developed for the residential class. However, we will adopt the proposed $4.80 charge as it is below both embedded and marginal costs for residential customers. The imposition of a residential customer charge is consistent with our movement of all other customer classes towards unbundled cost-based rates. The revenue from this charge is to be included in the baseline calculation.

2. Increase of Schedule <u>AD Demand Charge</u>

Schedule AD is one of two schedules for the Small and Intermediate Commercial and Industrial Class. Customers whose monthly peak demands fall between 20 kw and 500 kw are served under this schedule.

Schedule AD consists of a $10.00 customer charge, a $4.00/kw demand charge, and per kwh energy rates. SDG&E proposes to raise the demand charge to $5.00/kw as the current demand charge is far below the combined marginal costs of generation, transmission and distribution. SDG&E also believes that the slight increase in the demand charge will give a price signal to AD customers to migrate to time-of-use schedules.

DRA states that an increase of the demand charge is not necessary to induce migration from Schedule AD to other schedules with time-of-use rates. DRA submits that the higher average rate the categories of steam, nuclear, and hydro were within 10% of SDG&E-owned resources. Even when compared to this subset, SDG&E's fuel and purchased power expense was 78-143% higher than the average. The remaining operations and maintenance expense was 27-54% above the average.

The Alliance also investigated SDG&E's claim that low customer sales have caused higher rate levels. Here the Alliance examined expense levels on a dollar per kilowatt basis. Again, the Alliance's results show that SDG&E is above the average when compared to the other utilities.

The Alliance observes that a utility's rates reflect operating expenses, taxes, and a return on capital. On an individual basis, SDG&E ranks high in all of these areas. When taken together, SDG&E's rates become the highest in the country. The Alliance recommends that the Commission closely scrutinize all of SDG&E's revenue requirement expense items in an effort to control SDG&E's costs and the resulting bills to all customers. We will do so in SDG&E's upcoming general rate case.

VIII. Coordination With Other Proceedings

We are using the present offset rate proceeding as a forum to implement rate design policy. In order to design rates we must compile company revenues from all rate elements, including base rates and MAAC rates, not just offset revenues.

Because this situation is new, we are faced with the need to determine the appropriate base rate revenues for rate design purposes. If base rates are left unchanged, then base rate revenues will exceed the ERAM margin authorized in the utility's most recent general rate case, due to increases in sales since that time. To avoid this overcollection in the ERAM account, and because a new adopted sales forecast is now available, we elect to under Schedule AD is a sufficient incentive for customers to migrate.

We approve the small increase in the demand charge to \$5.00/kw. The increase is modest when measured against the marginal costs for the customer class. We note that SDG&E has withdrawn its restriction on the number of customers that may move from Schedule AD in a given year so that customers that are induced to migrate because of the higher demand charge are not prevented from moving to another schedule.

The adopted rates are shown as Tables 4, 5, and 6.

TABLE 4
ADOPTED RATES -- NON-TIME-OF-USE

Schedule	Customer Charge (\$/Mo)	Demand Charge (\$/KW-Mo)	Energy (Base) (\$/KWH)	Energy (Offset) (\$/KWH)	Energy Total (\$/KWH)
Residential	4.80				
Baseline			0.06799	0.00068	0.06867
Non-Baseline			0.08593	0.06669	0.15262
A	5.00	0.00	0.08871	0.02713	0.11584
AD	10.00	5.00	0.04960	0.02713	0.07673
PA	8.00	0.00	0.07109	0.02713	0.09822

use only the general rate case adopted base rate revenues (margin) for rate design purposes.

The effect on base rate revenues is seen at lines 1 and 2 of the table in Appendix B.

When SDG&E and other utilities implement rate design changes in future offset proceedings, they should revise base rates to reflect recovery of authorized base revenue amounts using most recently adopted sales forecasts. Because resetting of base rates may be an issue in I.86-10-001, we invite utility testimony on the issue in that investigation.

Findings of Fact

1. SDG&E's fuel and purchased power forecast for the period November 1, 1987 - October 31, 1988 is based upon more recent data than DRA's forecast.

2. The ECAC, AER and ERAM rate changes together produce a total revenue reduction of $72.3 million.

3. SDG&E currently is paying Alamito for 100 MW of capacity although its ECAC forecast reflects payment for 400 MW of capacity.

4. SDG&E has filed a complaint with FERC regarding the capacity payment that should be made to Alamito.

5. The outcome of the FERC litigation is unknown and cannot be predicted with any degree of confidence.

6. If the Alamito capacity payment is not made subject to 100% ECAC balancing account treatment, SDG&E will recover in the AER $5,863,200 for payments that it may not be required by FERC to make to Alamito.

7. A 100% ECAC balancing account treatment for the withheld Alamito capacity payment and associated interest payments will ensure that neither ratepayers nor shareholders are penalized by the outcome of the FERC litigation.

8. SDG&E has requested permission to adjust the AER by advice letter to reflect the Commission's eventual decision revising the gas rate structure in A.86-06-005.

has not had the opportunity to argue the issue in this case and, when considered in conjunction with the utility's pending general rate proceeding, this will afford SDG&E's ratepayers a modest improvement in rate stability.

However, in I.86-10-001 or the next time a new electric sales forecast is litigated, whichever opportunity comes first, we invite utility testimony on this issue.

All of the adopted revenue changes incorporated into the presently authorized rate design are shown on the table in Appendix B. The effect of sales changes to base rate revenues is shown on lines 1 and 2 of the table. The adopted rates are set forth in Appendix C.

Findings of Fact

1. SDG&E's fuel and purchased power forecast for the period November 1, 1987 - October 31, 1988 is based upon more recent data than DRA's forecast.

2. The ECAC, AER and ERAM rate changes together produce a total revenue reduction of $72.3 million.

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7. A 100% ECAC balancing account treatment for the withheld Alamito capacity payment and associated interest payments will ensure that neither ratepayers nor shareholders are penalized by the outcome of the FERC litigation.

9. The AER is intended to fix the company's fuel and purchased power expense at a single point in time.

10. Shareholders are to absorb any recorded differences in fuel and purchased power expense from the AER.

11. DRA has proposed that SDG&E's fuel oil inventory be given "lump sum" ratemaking treatment equivalent to placing the carrying cost of fuel oil inventory in the AER.

12. DRA's "lump sum" approach would single out fuel oil inventory for different ratemaking treatment.

13. The isolated treatment of fuel oil inventory proposed by DRA could result in perverse incentives for utility management to focus on inventory costs more than other energy costs.

14. SDG&E's marginal cost study is the only study submitted in this proceeding which purports to measure the costs of service on SDG&E's system.

15. UCAN has shown that the customer investment revenue requirement for existing and new customers should be reduced by 29% under an incremental/decremental approach.

16. UCAN has recommended that marginal generation costs should be multiplied by 1.15 to reflect SDG&E's maintenance of a 15% reserve margin.

17. FEA and the Alliance have shown that their method of allocating capacity costs among the customer classes is more accurate than the allocation method used by SDG&E and DRA.

18. A cap of a minimum 5.0% rate decrease is appropriate in the context of a substantial revenue decrease.

19. The revenue decrease to Schedule AD should not be constrained so that this customer group can be moved towards its marginal costs.

20. SDG&E and DRA should devise a method whereby standby revenue can be credited to the proper customer class.

8. SDG&E has requested permission to adjust the AER by advice letter to reflect the Commission's eventual decision revising the gas rate structure in A.86-06-005.

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16. UCAN has recommended that marginal generation costs should be multiplied by 1.15 to reflect SDG&E's maintenance of a 15% reserve margin.

17. FEA and the Alliance have shown that their method of allocating capacity costs among the customer classes is more accurate than the allocation method used by SDG&E and DRA.

18. A cap of a minimum 5.0% rate decrease is appropriate in the context of a substantial revenue decrease.

19. The revenue decrease to Schedule AD should not be constrained so that this customer group can be moved towards its marginal costs.

21. SDG&E, DRA, the Alliance, the FEA, the Hospitals, and the MinPros have entered into an agreement on the rate structure for large commercial and industrial customers.

22. The agreement is a major step towards unbundling SDG&E's rates and is a reasonable compromise among the signatories.

23. Noncoincident demand charges of $3.17 per kW (secondary), $2.52 per kW (primary), and $1.06 per kW (transmission) are preferable as they are more consistent with a gradual movement towards the recovery of fixed costs in fixed charges.

24. A 50% ratchet for the noncoincident demand charge is preferable as it is the more conservative choice and is consistent with a deliberate and careful movement towards unbundled rates.

25. A winter standby rate limiter of $0.26 per kWh is approriate as SDG&E is a summer peaking utility, and greater costs should be allocated to the summer period than to the winter period.

26. A credit of $0.50/kW for distribution facilities is appropriate where customers have paid for normal distribution facilities as part of a special facilities fee.

27. Closure of the PG-QF Schedule within eighteen months of the effective date of the adopted rates is sufficient time for small cogeneration projects under development to come on-line.

28. A residential customer charge of $4.80 per month is consistent with cost-based rates as the charge is below both embedded and marginal costs.

29. An increase of the Schedule AD demand charge from $4.00/kW to $5.00/kW is a modest increase when measured against the marginal costs for the customer class.

30. The Alliance has shown that SDG&E's costs as compared to other utilities' costs are above average in all expense categories and that these costs should be closely scrutinized in the upcoming general rate case.

31. This order should take effect on the date of issuance so that the revised rates can become effective on January 1, 1988.

20. SDG&E and DRA should devise a method whereby standby revenue can be credited to the proper customer class.

21. SDG&E, DRA, the Alliance, the FEA, the Hospitals, and the MinPros have entered into an agreement on the rate structure for large commercial and industrial customers.

22. The agreement is a major step towards unbundling SDG&E's rates and is a reasonable compromise among the signatories.

23. Noncoincident demand charges of $3.17 per kW (secondary), $2.52 per kW (primary), and $1.06 per kW (transmission) are preferable as they are more consistent with a gradual movement towards the recovery of fixed costs in fixed charges.

24. A 50% ratchet for the noncoincident demand charge is preferable as it is the more conservative choice and is consistent with a deliberate and careful movement towards unbundled rates.

25. A winter standby rate limiter of $0.26 per kWh is approriate as SDG&E is a summer peaking utility, and greater costs should be allocated to the summer period than to the winter period.

26. A credit of $0.50/kW for distribution facilities is appropriate where customers have paid for normal distribution facilities as part of a special facilities fee.

27. Closure of the PG-QF Schedule within eighteen months of the effective date of the adopted rates is sufficient time for small cogeneration projects under development to come on-line.

28. A residential customer charge of $4.80 per month is consistent with cost-based rates as the charge is below both embedded and marginal costs.

29. An increase of the Schedule AD demand charge from $4.00/kW to $5.00/kW is a modest increase when measured against the marginal costs for the customer class.

30. The Alliance has shown that SDG&E's costs as compared to other utilities' costs are above average in all expense categories and that these costs should be closely scrutinized in the upcoming general rate case.

32. It is reasonable to revise base rates to collect only the base revenue amount authorized in SDG&E's most recent general rate case, through rates calculated using the revised sales forecast adopted in this proceeding.

Conclusions of Law

1. The withheld Alamito capacity charge should be given 100% ECAC balancing account treatment since the amount of this payment is substantial and subject to the outcome of litigation at FERC.

2. The revenue allocation based upon an EPMC allocation constrained by a cap of a minimum 5.0% rate decrease is a fair balancing of the need to move rates towards marginal costs with the need to avoid disruptive rate changes.

3. The agreement of the parties on the basic structure of the large commercial and industrial rate schedule is a reasonable compromise based upon the evidentiary record in this proceeding.

4. The rates shown in Appendix C are just and reasonable and should be adopted.

ORDER

Therefore, IT IS ORDERED that:

1. Five days after the effective date of this order, San Diego Gas & Electric Company (SDG&E) shall file revised tariffs effective January 1, 1988 reflecting the rates as shown in Appendix C.

2. The 300 MW capacity payment and related interest payments to Alamito Company is subject to 100% Energy Cost Adjustment Clause (ECAC) balancing account treatment.

3. SDG&E and the Division of Ratepayer Advocates (DRA) shall devise a method for crediting standby revenues to the appropriate customer class.

4. Schedule PG-QF shall be closed to facilities above 20 kW by June 30, 1989, eighteen months from the effective date of the

31. This order should take effect on the date of issuance so that the revised rates can become effective on January 1, 1988.

Conclusions of Law

1. The withheld Alamito capacity charge should be given 100% ECAC balancing account treatment since the amount of this payment is substantial and subject to the outcome of litigation at FERC.

2. The revenue allocation based upon an EPMC allocation constrained by a cap of a minimum 5.0% rate decrease is a fair balancing of the need to move rates towards marginal costs with the need to avoid disruptive rate changes.

3. The agreement of the parties on the basic structure of the large commercial and industrial rate schedule is a reasonable compromise based upon the evidentiary record in this proceeding.

4. The rates shown in Appendix C are just and reasonable and should be adopted.

O R D E R

Therefore, IT IS ORDERED that:

1. Five days after the effective date of this order and no later than December 29, 1987, San Diego Gas & Electric Company (SDG&E) shall file revised tariffs effective January 1, 1988 reflecting the rates as shown in Appendix C.

2. The 300 MW capacity payment and related interest payments to Alamito Company is subject to 100% Energy Cost Adjustment Clause (ECAC) balancing account treatment.

3. SDG&E and the Division of Ratepayer Advocates (DRA) shall devise a method for crediting standby revenues to the appropriate customer class.

4. Schedule PG-QF shall be closed to facilities above 20 kW by June 30, 1989, eighteen months from the effective date of the adopted rates. The schedule also shall be revised to apply to third party situations.

adopted rates. The schedule also shall be revised to apply to third party situations.

5. A credit is $0.50/kW shall be given to customers that have paid for normal distribution facilities in special facilities charges.

6. Schedules AO-TOU and AO6-TOU shall be closed to new customers as of July 1, 1988.

7. SDG&E and DRA shall study reserve requirements and the reliability needs based on value of service for the different customer classes in the 1989 TY General Rate Case.

8. SDG&E and DRA shall submit in the 1989 TY General Rate Case studies which explain why the company's costs and rates are high compared to other utilities' costs of service and rates.

This order is effective today.

Dated ____________________, at San Francisco, California.

5. A credit is $0.50/kW shall be given to customers that have paid for normal distribution facilities in special facilities charges.

6. Schedules AO-TOU and A06-TOU shall be closed to new customers as of July 1, 1988.

7. SDG&E and DRA shall study reserve requirements and the reliability needs based on value of service for the different customer classes in the 1989 TY General Rate Case.

8. SDG&E and DRA shall submit in the 1989 TY General Rate Case studies which explain why the company's costs and rates are high compared to other utilities' costs of service and rates.

This order is effective today.

Dated DEC 22 1987, at San Francisco, California.

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

APPENDIX B

SAN DIEGO GAS AND ELECTRIC COMPANY
Attrition Year 1988 - California Jurisdiction
Revenue Changes Adopted for Revenue Allocation and Rate Design

LINE	ITEM	PRESENT RATE REVENUES ** ($ million)	ADOPTED REVENUES ($ million)	REVENUE CHANGES ($ million)
		(a)	(b)	(c)
	BASE:			
1	Base (margin)	635.709	635.709	0.000
2	Sales change	44.249	0.000	(44.249)
3 *	Attrition (includes estimated 1988 effects of TRA)	0.000	(5.954)	(5.954)
4 *	Decommissioning	0.000	22.017	22.017
5 *	MAAC pre-COD transfer	0.000	138.452	138.452
6	Subtotal	679.958	790.224	110.266
	MAAC:			
7	SONGS pre-COD interim rates @ 1.897 c/kwh	239.139	0.000	(239.139)
8	SONGS pre-COD amortization	0.000	(19.140)	(19.140)
9 *	SONGS post-COD interim rates	0.000	14.287	14.287
10	SONGS post-COD amortization	0.000	10.841	10.841
11	Subtotal	239.139	5.988	(233.151)
	OTHER OFFSETS:			
12	CALPAC	0.000	0.000	0.000
13	ECAC	443.549	349.711	(93.838)
14	AER @ 0.327,0.250 c/kwh	41.222	31.515	(9.707)
15	ERAM amortization @ (0.282) c/kwh present rate	(35.549)	(4.298)	31.251
16	ERAM/SONGS 1 memo account (in attrition)	0.000	20.560	20.560
17	Tax Reform Act, 1987 refund		(deferred to 1988)	
18	Decommissioning tax refund		(deferred to 1988)	
19 *	SUBTOTAL (all above)	1,368.319	1,193.700	(174.619)
20	OTHER REVENUES	15.822	15.822	0.000
21	CPUC reimbursement fees @ 0.012 c/kwh	1.513	1.513	0.000
22 *	TOTAL	1,385.654	1,211.035	(174.619)

Notes: * Amounts depend on adopted rate of return, herein 12.75% ROE.
** Based on adjusted sales of 12,606.18 GWH.

Adopted base and MAAC revenues must be reduced by City of San Diego franchise fee differential for rate design purposes. Table shows correct margin.

(END OF APPENDIX B)

APPENDIX C
Page 2

FINAL DECISION
EQUAL PERCENT DECREASE TO DEMAND AND ENERGY
Decrease = $ 143 million, 5 % Cap

					PROPOSED RATES					
Customer Class	Customer Charge ($/mo)	Max Demand ($/KW)	Winter On-Pk Demand ($/KW)	Summer On-Pk Demand ($/KW)	Summer On-Pk Energy ($/KWH)	Summer Semi-Pk Energy ($/KWH)	Summer Off-Pk Energy ($/KWH)	Winter On-Pk Energy ($/KWH)	Winter Semi-Pk Energy ($/KWH)	Winter Off-Pk Energy ($/KWH)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
AL-TOU										
Secondary	20.00	3.05	3.36	14.42	0.08934	0.05777	0.04369	0.08011	0.05053	0.04250
Primary	20.00	2.42	3.36	14.42	0.08359	0.05502	0.04089	0.07492	0.04691	0.03868
Transmission	20.00	1.02	1.34	9.07	0.08109	0.05337	0.03967	0.07267	0.04551	0.03752
A6-TOU										
Secondary	600.00	3.05	4.01	17.18						
Primary	600.00	2.42	4.01	17.18	0.08359	0.05502	0.04089	0.07492	0.04691	0.03868
Transmission	600.00	1.02	1.79	11.01	0.08109	0.05337	0.03967	0.07267	0.04551	0.03752