In the Matter of the Application of San Diego Gas & Electric Company for Authority to Increase its Rates and Charges for Electric, Gas, and Steam Service, effective January 1, 1993.

Order Instituting Investigation into the rates, charges and practices of the San Diego Gas & Electric Company

Decision No. 92-12-019, Application No. 91-11-024 (Filed November 15, 1991), Investigation No. 92-02-004 (Filed February 5, 1992)

CALIFORNIA PUBLIC UTILITIES COMMISSION

1992 Cal. PUC LEXIS 867; 46 CPUC2d 538

December 3, 1992

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PANEL: [*1]

Daniel Wm. Fessler, President; John B. Ohanian, Patricia M. Eckert, Norman D. Shumway, Commissioners

FESSLER, President of the Commission:

Summary: Today we adopt, with noted exceptions, a settlement proffered by San Diego Gas & Electric, our Division of Ratepayer Advocates, the City of San Diego, and the Utility Consumer Action Network which covers most of the issues pertaining to the utility's general rate case.[1] We take this opportunity to address the role which "all party" or unanimous settlements can play in assisting the Commission in discharging its regulatory responsibilities.[2] We also indicate the areas in which the instant settlement proposal was, from our perspective, deficient and where we anticipate that participants in future proceedings will improve on the process.[3] Our decision rejects key recommendations of the learned Administrative Law Judge while echoing some of the concerns clearly articulated in his proposed decision.

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I. Background and Procedural History:

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[1] As we shall detail, the settlement does not resolve the following issues pertaining to the utility's revenue requirement: (1) emerging business enterprise costs, (2) demand-side management program costs and incentive rewards, (3) affiliate issues, and (4) deferred costs.

[2] As used in this opinion an "all party" settlement is one sponsored by all of the parties to the Commission proceeding. Such a proposal is to be distinguished from an "uncontested" settlement which may not be sponsored by all of the parties but in which the non joining parties do not contest the terms pursuant to Rules 51.4 -- 6 of our Rules of Practice and Procedure.

In the instant case the California Energy Commission entered the proceeding for a very limited purpose and that with respect to that purpose it has not agreed to the position taken by all other parties. Such a factor raises the immediate question as to whether the failure of a single issue participation party to join in sponsoring a settlement deprives it of the "all party" quality to which our enunciated policy would apply. We conclude that it does not. The failure of a single issue participant to co-sponsor a settlement means that as to that issue we will not take the recommendation of the sponsoring parties as potentially establishing reasonableness.

[3] We intend that our views concerning the role and content of settlements as expressed in Part II B this decision shall be precedential in respect to future Commission proceedings. To this extent only, we expressly modify the non-precedential qualities of settlements pursuant to Rule 51.8.

A. Background:

In the period since San Diego Gas & Electric Company's (SDG&E) last General Rate Case, the company has been absorbed in what its President Jack E. Thomas describes as a "three-year roller coaster ride of would-be mergers involving SDG&E, Tucson Electric Power Company and Southern California Edison (SCE)." During that time, the company faced constant uncertainty as to whether it would meet its future energy and service needs as a stand-alone company or as part of a larger system that might come equipped with excess capacity or energy. The roller coaster came to rest in May of 1991 when the Commission issued a decision rejecting the proposed merger of SDG&E and SCE.

As it filed this application in November of 1991, SDG&E was just beginning to settle into the reality of its continued life as a stand-alone utility. The company's management expressed its desire to seize the opportunity to redefine its corporate mission. In doing so, it renewed its resolve to maintain the lowest energy costs in the state while improving reliability, increasing its earnings per share, and improving its relationship with all of the constituencies [*3] it serves. The company also pledged to weigh the environmental, health, and safety consequences of each of its actions and fulfill its specific mandate as a regional utility to enhance and preserve the quality of life in its service territory.

In offering its new mission to the Commission in this proceeding, SDG&E invites our scrutiny of the company's goals, its plan to meet those goals, and the reasonableness of the revenues it says it needs to get the job done. SDG&E asked for a base rate revenue requirement totalling $ 1,049,739,000 (an overall increase of 8.7%) for its electric customers, $ 190,287,000 (an overall increase of 4.2%) for its gas customers, and $ 1,869,000 (an overall increase of 120.3%)

SDG&E, the Commission's Division of Ratepayer Advocates (DRA), the Utility Consumer Action Network (UCAN), and the City of San Diego have offered a settlement covering most of the issues raised in this proceeding. In addition, SDG&E, DRA, and UCAN offered joint recommendations concerning demand-side management (DSM) activities.

We adopt the proposed settlement having concluded that it conforms to the broad guidelines which we now announce. Because we have been less than clear [*4] in educating parties concerning the criteria we will apply to settlements, we share responsibility with the settling parties for the deficiencies which we identify in the proposal.

Our decision approves a base rate revenue requirement of $ 956,072,000 (an overall increase of 2.28%) for electric customers, $ 178,818,000 (an overall increase of

1.7%) for natural gas customers and $ 1,608,000 (an overall increase of 93.1%) for steam customers.

B. Procedural History:

Prior to this proceeding, SDG&E's most recent General Rate Case was filed in December, 1987, for Test Year 1989.[4] The rate case plan schedule called for SDG&E to file an application for a 1992 Test Year General Rate Case. In Decision (D.) 89-12-052, the Commission ordered SDG&E to defer its filing because of its then-pending application to merge with SCE. In D.91-07-014, we specified that a 1993 Test Year should be used for the next SDG&E General Rate Case and directed the company to file its application on November 15, 1991. SDG&E was also allowed to forego its obligation to file a notice of intent. Finally, the Commission agreed to defer two issues to other proceedings. Resource plan issues were to be addressed [*5] in Investigation (I.)89-07-004, the Biennial Resource Plan Update, and the electric sales forecast was to be derived from the sales forecast adopted in the decision in SDG&E's Energy Cost Adjustment Clause (ECAC) proceeding applicable to the May, 1992 through April, 1993 forecast period (Application 91-09-059). This application was filed on November 15, 1991.

On May 8, 1992, after DRA had filed its testimony in response to SDG&E's application, a Settlement Agreement addressing most revenue requirement issues was filed with the Commission. The Settlement bore the signatures of representatives of SDG&E, DRA, the City of San Diego and UCAN. Hearings were held June 9 and June 16-18, 1992 to take evidence on matters not included in the Settlement. These included a proposal of the California Energy Commission (CEC) for the addition of two new items to SDG&E's Research, Development and Design (RD&D) program, a Joint Recommendation for DSM programs and funding, and a proposal of the City of San Diego to direct SDG&E to reduce or eliminate the use of floodlights to illuminate the facade of its headquarters [*6] building.

In response to direction from Administrative Law Judge Steven Weissman, on July 2, 1992, the Settling Parties served a Joint Comparison Exhibit, explaining and

[4] Application (A.)87-12-003, which led to Decision (D.)88-09-063 and D.88-12-085.

clarifying terms in the Settlement. Hearings were held on July 27-29, 1992, to clarify issues raised by the Comparison Exhibit. At the request of the parties, the ALJ allowed for the filing of Opening Briefs on August 26, 1992 and Reply Briefs on September 11, 1992. An Update Hearing was held on September 14, 1992, and parties were allowed to file additional briefs on the Update issues by September 25, 1992. The first phase of this proceeding was submitted on September 25, 1992.

II. The All Party Settlement:

A. Scope of the Settlement:

As they did in SDG&E's last general rate case, the last ECAC proceeding, and last attrition adjustment, the active parties in this proceeding offered a settlement. For test year 1993, the settlement results in an increase in electric base rate revenues of $ 71.996 million or 5.01%, an increase in gas base rate revenues of $ 17.512 million or 3.83%, and an increase in steam base rate revenues of $ 882,000 or 92.45%. In this instance, the settlement covers most, but not [*7] all, of the issues raised in the revenue requirements phase.

Issues that were not resolved in the settlement include the following:

1. Emerging business enterprise costs.

This subject was previously referred to as women and minority business enterprises. DRA and SDG&E have stipulated to adoption of the rate increase proposed in a related report prepared by the Commission Advisory and Compliance Division (CACD) which was released after the filing of settlement.

2. Demand-side management program costs and incentive rewards.

Although these costs were not included in the settlement, the settling parties have offered joint testimony on all issues other than the external lighting of SDG&E's corporate headquarters building. SDG&E and the City of San Diego offer conflicting testimony on the latter subject.

3. Affiliate issues.

After filing the settlement, SDG&E agreed to support the cost of services recommendation included in paragraphs 10 through 12 of Chapter 5 and the report on affiliated company's recommendation expressed at paragraph 22 of Chapter 5 of the DRA report on results of operation. DRA agreed to withdraw from that report its recommendations regarding shared directors [*8] and corporate costs.

4. Deferred costs.

The settling parties agreed to defer certain cost items included in SDG&E's original filing in this case, for final resolution in other proceedings. For instance, certain expenses related to operation and maintenance of the San Onofre Nuclear plants are deferred to SCE's 1993 attrition filing. In addition, the final revenue requirement adopted in this proceeding to reflect post-retirement benefits other than pensions would be changed to reflect the outcome of I.90-07-037 if a decision in that docket adopted a method that is different than the pay-as-you-go method. Further, the settlement contains no dollars for low emission vehicle (LEV) program expenses. The parties propose that LEV cost for SDG&E be determined in I.91-10-029, which is currently considering policy issues related to LEVs. Finally, the settling parties propose that cost related to environment projects be tracked in a memorandum account for potential recovery in subsequent proceedings.

B. Role of settlements in disposing of the Commission's responsibilities:

In recent years we have had increasing occasion to speak to the role of settlements and the strength and weakness [*9] of this mechanism when contrasted with the traditional evidentiary hearing. As we shall note, our experience has been paralleled by that of commissions vested with similar regulatory responsibilities in other states.

1. Our policy on all party settlement proposals:

We envision settlements as a vehicle for executing rather than formulating Commission policy. With this objective in mind, we are prepared to adopt a settlement that meets sponsorship and content criteria which pertain to both the identity and capacity of the sponsoring parties and the terms of their recommendation. As a precondition to our approval the Commission must be satisfied that the proposed all party settlement:

a. commands the unanimous sponsorship of all active parties to the instant proceeding;

b. that the sponsoring parties are fairly reflective of the affected interests;

c. that no term of the settlement contravenes statutory provisions or prior Commission decisions;[5] and,

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[5] In formulating this criteria we do not intended to preclude the sponsoring parties from suggesting changes in established Commission policy or precedent or proposing policy in areas we have yet to address. However, we expect the sponsoring parties to clearly identify those portions of any proposed all party settlement which would require modification of Commission policy or the for-

d. that the settlement conveys to the Commission sufficient information to permit us to discharge our future regulatory obligations with respect to the parties and their interests.

[*10]
2. The precedents and reasons which prompt the adoption of this policy:

Before detailing the precedents and reasons which have brought us to these views, we will summarize our policy on the role which all party settlements can play in furthering the work of the Commission.

Our recent history with respect to settlements begins with the seminal proceeding in *Re Pacific Gas and Electric Company*, D.88-12-083, 30 CPUC2d 189 (1988).[6] That order approving a settlement agreement excluding from rate base case all costs incurred by PG&E in the construction, ownership and, operation of the Diablo Canyon nuclear power plant, involved the first application of the settlement procedure rules formulated in Rulemaking proceedings R.84-12-028. Few cases could more clearly instruct the successors to those Commissioners of the goals they had sought to accomplish. We are told that "[t]here is a strong public policy favoring the settlement of disputes to avoid costly and protracted litigation." *Id., at 221.* Our predecessors were consciously building upon the proposition advanced in D.87-04-034 that settlements involved an "appropriate method of alternative ratemaking . . ." Id. The complexity [*11] and profound nature over time of the Diablo Canyon proceeding convinced our predecessors that for that case settlement criteria and procedures should closely approximate those used by both state and federal courts in disposing of class actions. In explaining the intended use of these procedures the Commission declared:

> When a class action settlement is submitted for approval, the role of the court is to hold a hearing on the fairness of the proposed

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mulation of heretofore unannounced policy. Our goal is to always make policy amendment a conscious decision of the Commission. Further, the sponsoring parties must understand that the Commission is perfectly free to reject the recommendation by adhering to established policy or refusing to go beyond it.

[6] We note in passing that the settlement adopted by the Commission in *Re Pacific Gas and Electric Company*, was neither an all party proposal nor uncontested. While our discussion today is limited to our policy on all party settlements, nothing in our statement of views should be taken to indicate an indisposition to adopt settlements contested pursuant to Rule 51.6 of our Rules of Practice and Procedure.

settlement. Proposed Rule 51.6 provides that if there are contested material issues in a proposed settlement, a hearing will be scheduled. However, the fairness hearing is not to be turned into a trial or rehearsal for trial on the merits. [citations] The court must stop short of the detailed and thorough investigation that it would undertake if it were actually trying the case. [citations].

[*12]

The standard used by the courts in the review of proposed settlements is whether the class action settlement is fundamentally fair, adequate and reasonable. [citation] The burden of proving that the settlement is fair is on the proponents of the settlement. [citations] Proposed Rule 51.1(e) provides that this Commission will not approve a settlement unless the '. . . settlement is reasonable in light of the whole record, consistent with law, and in the public interest.'

30 CPUC2d 222.[7]

In *Re San Diego Gas and Electric Company*, D.90-08-068, 37 CPUC2d 346 (1990), we were presented with four [*13] unanimous settlements arising out of our demand side management collaborative.[8] In adopting the four settlements with what

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[7] One month prior to our adoption of the settlement in *Re Pacific Gas and Electric Company*, supra, the Commission made operative general rules governing stipulations and settlements, Article 13.5 of the Commission Rules of Practice as amended on November 11, 1988, distinguished between those stipulations and settlements which command the allegiance of all parties to the proceeding as opposed to those which are contested pursuant to Rule 51.6. Since the settlement before us in this proceeding commands the unanimous sponsorship of all parties, we limit our discussion to such proposals.

[8] Of the four settlements, the one presented by SCE along with eight joining parties, posed the greatest difficulty for the Commission. The deficiencies were not dissimilar to the objections raised by the Administrative Law Judge to the proposal in this proceeding.

. . . The settlement contained no summary or listing of its agreements that can be displayed here, since it consists primarily of voluminous attachments that are referenced but not summarized in the text of the settlement, together with some specific agreements that are contained in the text of the settlement. At the request of the ALJ, SCE produced . . . an index to the attachments, identifying we described as minor modifications designed to harmonize the efforts of the four participating energy utilities, we made the following pertinent observations:

We recognize, as the settlements point out to us, that these settlements resulted from a good deal of give and take among the parties and reflect interrelated trade-offs that may not be apparent to a reviewer who did not participate in the settlement discussions. For that reason, we do not delve deeply into the details of the settlements and attempt to second-guess and reevaluate each aspect of the settlement, so long as the settlements as a whole are reasonable and in the public interest. . . .
[*14]

This declaration of a standard of review followed an earlier discussion which clearly articulated appreciation that the settlement process empowers the parties to a degree which somewhat diminishes the fact finding role of the Commission.

> While the programs set forth in these settlements offer a way to quickly revitalize the DSM energy efficiency programs at the four largest California energy utilities, the trade-off for this is our acceptance of the judgment of the settling parties on the appropriateness of some details of the settlement in the absence of evidentiary hearings or specific substantiation of those details. This trade-off is inherent in many of the settlements brought to the Commission for consideration.

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some of the duplicating portions of the application, while other attachments replace portions of the application and still other attachments provide new information. . . . However, even with the index, the settlement fails to identify or explain each of the specific changes made to the application.

SCE and other parties to this settlement are put on notice that we expect better than this in the presentation of settlements to this Commission. At a minimum, a settlement should clearly lay out the substance of the agreements reached by the parties and the effect of those agreements on the positions previously taken by parties to the proceeding. . . . The confusion created by the disorganized type of settlement presented to us here unnecessarily increases the time it takes to review the settlement. It also increases the risk that the settlement will be rejected for lack of clarity, misunderstood, or interpreted contrary to the intent of the settling parties, and the parties should require no further spur to clearly lay out their agreement. Were this settlement not part of a consolidated proceeding with three other utilities and were we not committed to expeditious action on these applications to revitalize DSM programs, it would have been sent back to the parties for clarification.
37 CPUC2d at 354.

> In judging such settlement the Commission retains the obligation to independently assess and protect the public interest. . . .[9]

[*15]
37 CPUC2d at 360.

Most recently the perceived advantages of the settlement process were addressed in a concurring opinion uttered in the context of our decision respecting *Natural Gas Procurement and Reliability Issues*, R.90-02-008, CPUC2d , 127 PUR4th 417, 462 (1991). There COMMISSIONER FESSLER noted the increasing presence of multiple parties in Commission proceedings and the procedural dysfunction of the attempt to discharge our complex tasks in the confines of a trial type hearing. In announcing a preference for a ". . . cooperative attitude toward problem solving [which would] achieve substantial procedural economies while enhancing our ability to fashion general rules and specific outcomes which guard the public advantage . . ." the Commissioner noted:

> Two factors are clearly in tension. Our challenge is to balance them. First, the members of this Commission may not surrender ultimate regulatory responsibility to the very persons whose actions or inaction are affected with a public interest. Second, for a settlement forum to be productive the participants must envision advantage as a consequence of open and committed participation. Excessive deference would betray [*16] [the Commission's] public trust. Refusal to value a settlement agreement would deprive the parties of any incentive to negotiate in good faith. In a worst case scenario, our use of alternative dispute resolution machinery with routine indifference to its suggested conclusion would leave the parties with only two alterna-

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[9] Revealing the tension implicit in deferring to the judgment of the settling parties while retaining an ultimate authority as the decision maker, the Commission closed the quoted paragraph with the following statement:

. . . Parties to the settlement may chafe at what they perceive as intrusion on bargained-for deals and may believe that this Commission should simply take their word that the settlements serve the interest of the public in addition to the interests of the settling parties. However, settlements brought to this Commission for review are not simply the resolution of private disputes, such as those that may be taken to a civil court. The public interest and interests of ratepayers must also be taken into account, and the Commission's duty is to protect those interests.
Id.

> tives. They could either posture for position in an eventual trial, or procrastinate in efforts to prolong a preliminary process. For each participant the election would be dictated by the impact of time.

127 PUR4th at 463.

In articulating a policy on the role of settlements, the opinion suggests a willingness to defer to proposals which satisfy two criteria. "First, that the settlement commands broad support among participants fairly reflective of the affected interests. Second, that it does not contain terms which contravene statutory provisions or prior Commission decisions." Id. If both conditions are met, the standard of review articulated in *Re San Diego Gas and Electric Company*, supra, 37 CPUC2d 346, 363 is consonant with our obligation to guard the public interest. The application of such procedures as an "appropriate method of alternative ratemaking" [*17] has already been embraced by the Commission in *Re Pacific Gas and Electric Company*, supra, 30 CPUC2d 189, 221.

Both this view and approach are strongly supported in the recent decisions of Commissions in other states. *In Re Cleveland Electric Illuminating Company*, 99 PUR4th 407, 449-50 (1989), the Ohio Public Utilities Commission declared that:

> [t]he ultimate question to be answered by the Commission is whether, in light of the whole record, the Stipulation is reasonable. In considering the reasonableness of a settlement, the Commission has . . . recognized a need to analyze the following criteria:
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> 1) Is the settlement a product of serious bargaining among capable, knowledgeable parties:
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> 2) Does the settlement, as a package, benefit ratepayers and the public interest?
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> 3) Does the settlement package violate any important regulatory principle or practice?

Similar criteria were enunciated by the Texas Public Utility Commission which also summarized its reasons for preferring to rely upon settlements in the course of an order accepting an electric rate proposal that combined a prudence disallowance of a portion of El Paso Electric Company's investment in Palo Verde nuclear facility [*18] and a rate moderation plan.

> It is the policy of this Commission to encourage the settlement of proceedings before this Commission, for the following reasons:
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> (a) Settlements usually reduce the expense to ratepayers and taxpayers of resolving the issues presented;

> (b) Settlements usually conserve the resources of the Commission available for ratemaking;
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> (c) Settlements allow the parties to the settlement to avoid the risk that a litigated resolution to the issues may produce results that are unacceptable to such parties; and
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> (d) Settlements promote peaceful relations among the parties.

In Re El Paso Electric Company, 14 Tex. PUC Bull. 929, 101 PUR4th 405, 409 (1988).

Finally, the Rhode Island Commission clearly recognized that in considering a settlement the focus must be upon the reasonableness of the whole rather than upon a detailed examination of each constituent element. "[T]he Commission's role in reviewing an agreement such as this Stipulation is to 'ensure the overall reasonableness of the agreement, without necessarily coming to an express conclusion about each element of the agreement.'" *In Re New England Telephone and Telegraphy Company*, 109 PUR4th 343, 347 (1989). [*19]

3. The Proposed Decision of the Administrative Law Judge:

The ALJ approached the proffered settlement employing what he described as a "three-prong test" for approval derived from Rule 51.1 of our Rules of Practice and Procedure. In his view, the Commission would "not approve a settlement, whether or not it is contested, unless the settlement is: (1) reasonable in light of the whole record, (2) consistent with the law, and (3) in the public interest." It was also noted that Rule 51.1 requires that when a settlement pertains to a proceeding under the rate case plan that it be supported by a comparison exhibit indicating the impact of the settlement in relation to the utility's application. If, as here, the Commission staff supports the settlement, it must prepare a similar exhibit indicating the impact of the proposal in relation to the issues it contested, or would have contested, in a hearing.

The ALJ correctly noted that, as originally submitted, the all party settlement lacked the comparison exhibits required by Rule 51.1. Accordingly, he directed the parties to prepare a joint comparison exhibit including what he described as "account-by-account detail not previously [*20] provided." The parties were also directed to offer comment on how, in their estimate, the settlement comported with the three-prong test derived from Rule 51.1. The parties complied with these directives.

Notwithstanding the compliance of the parties, the ALJ concluded that the settlement was not "reasonable in light of the record as a whole because, in a significant number of instances, there is no prima facie showing to support its recommendations."[10] In his view:

> The California Constitution (Article 12, Section 6) empowers the Commission to fix rates for regulated utilities and *Section 454 of the Public Utilities Code* specifies that the Commission cannot raise rates except upon a showing before the Commission and a finding by the Commission that the increase is justified. Even when a utility request is unopposed (i.e., where there is no dispute) there must still be an adequate showing to support the rate request. As the Commission stated so clearly in a 1987 rate decision concerning Pacific Bell, "(t)he inescapable fact is that the ultimate burden of proof of reasonableness, whether it be in the context of test-year estimates, prudence reviews outside a particular test year, [*21] or the like, never shifts from the utility which is seeking to pass its costs of operations onto ratepayers on the basis of the reasonableness of those costs. Whenever the utility comes before this Commission seeking affirmative rate relief, it fully exposes its operations to our scrutiny and review. It must justify the reasonableness of its request and its operations by making at least a prima facie case of reasonableness, even in the absence of opposition. Where it faces opposition, its reasonableness showing is naturally a more difficult undertaking." (27 CPUC2d 1, 21; D.87-12-067)
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> The elimination of opposition no more relieves the utility of its burden of proof than does the absence of opposition. The Commission recognized this fact when it established the rules under which settlements are reviewed. If evidence of the existence of an agreement among all parties comprised sufficient showing to find a rate request reasonable, then the rules could simply state that whenever all parties bargain in good faith and agree to a settlement, the Commission would adopt it without review. Instead, the Commission [*22] created a three-part test that must be met in order to approve any settlement "whether contested or uncontested": it must be "reasonable in light of the whole record, consistent with the law and in the public interest."[11]

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10 Proposed decision of Administrative Law Judge Weissman at page 91.

11 *Id.*, at pages 95-96 (emphasis original).

For reasons which we shall now detail, we disagree with the ALJ that an all-party settlement requires the introduction before the ALJ of a sufficient quantum of evidence to establish prima facie that the settlement provisions are "reasonable."

4. Our review of the all party settlement:

We agree that Section 454 *of the Public Utilities Code* precludes our raising rates except upon a showing that the new rate is justified. Bearing the requisite burden of proof in a trial type hearing is surely one way in which that showing may be accomplished. However, in our view, the ALJ failed to apply our policy determination clearly uttered in Re Pacific Gas and Electric Company, supra, 30 CPUC2d at 221, that the proffer of an all party settlement is an appropriate method of alternative rate-making. Instead, he proposes to place the utility at risk for a proceeding which will have used the settlement as a "rehearsal [*23] for trial on the merits." This is precisely what we disavowed in our discussion of what was then proposed Rule 51.[12] Also ignored was our admonition in *Re San Diego Gas and Electric Company*, supra, 37 CPUC2d 346, 363, that "we do not delve deeply into the details of settlements and attempt to second-guess and re-evaluate each aspect of the settlement, so long as the settlements as a whole are reasonable and in the public interest. . . ."[13]

Sponsorship criteria: The proposed settlement in so far as it disposes of issues in the application of San Diego Gas & Electric Company for authority to increase its rates commands the unanimous sponsorship [*24] of the utility, the City of San Diego, UCAN and our Division of Ratepayer Advocates. These sponsors embrace

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[12] *Id.*, at 222.

[13] Nor can we agree with the ALJ that our acceptance of this settlement is precluded by the Commission's decision in *Re Pacific Bell*, D.87-12-067, 27 CPUC2d 1 (1987). Pacific Bell, which we affirm, did not enunciate rules respecting the approval of settlements. None was proffered in that proceeding. Further, it was decided before our adoption of Chapter 13.5 of our Rules of Practice and Procedure governing stipulations and settlements, and the enunciation of our views in *Re Gas and Electric Company*, supra, 30 CPUC2d 189.

the totality of the active parties to Phase I of the proceeding[14] and thus satisfy our requirement that the settlement be predicated on "all party sponsorship."

We now pass to the issue of full representation of affected interests. As noted in our review of recent precedent, a critical factor in our decision to adopt a settlement is confidence that it commands broad support among participants fairly reflective of affected interests.[15] Here we find that the settlement is sponsored by a range of parties ideally positioned to comment on the operation of the utility and ratepayer perception. As noted by the ALJ, SDG&E has recently emerged from three years of "would-be mergers." In our experience, the proceedings before this Commission subjected the utility to the intense interest and scrutiny of the City of San Diego and the San Diego based Utility Consumer Action [*25] Network (UCAN). It is therefore of significant moment that both the City and UCAN have joined our own Division of Ratepayer Advocates in sponsoring an all-party settlement to this rate case.

Content criteria: Having concluded that the settlement passes muster under the first of our review criteria, we next inquire whether it contains terms which contravene statutory provisions or prior Commission decisions. No statutory provisions are offended by the terms of this settlement. However, there are several instances in which the settlement would produce a result inconsistent with prior Commission decisions. In the discussion that follows, we will summarize the details of the settlement in the context of the initial positions of the parties and, where applicable, address the appropriate disposition of elements in the settlement that challenge prior Commission decisions.

The second of our content [*26] criteria has proven quite problematic with respect to the instant settlement. As we have just stated, to gain our approval an all party settlement must:

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[14] An exception is the California Energy Commission, which limited its participation to a relatively narrow issue concern funding for RD&D. The Energy Commission's concerns are discussed in detail, below.

[15] In *Re San Diego Gas and Electric Company*, supra, 37 CPUC2d 346, 360, we put it this way: "In evaluating settlements, one factor we consider is the range of interests represented by the parties to the settlements and any opposition to the settlements, as well as the settlement itself."

> . . . convey to the Commission sufficient information to permit us to discharge our future regulatory obligations with respect to the parties and their interests.

As was detailed in the proposed decision, SDG&E has failed, in this case, to present an initial showing that sufficiently describes, explains and justifies the requested revenue requirement.

The purpose of a general rate case is to develop and adopt sound, informed estimates of the reasonable costs to be incurred in the test year. We know that our adopted levels of revenues and expenses may be at variance with actual experience. However, we must be sufficiently informed to know that adopting a given estimate makes sense. Part of this process involves making sure that we do not repeatedly approve revenues to meet a one-time cost. When a utility's expense estimate includes the performance of a task it had planned to accomplish with previously authorized funds, we will want to know why the utility did not spend its funds as planned the first time around and will be [*27] hesitant to charge ratepayers twice for the same expense. In addition, we want to be confident that the activities being undertaken by the utility are lawful and otherwise consistent with public policy.

The company often does not even mention the name of major programs or activities and almost never adequately explains its basis for forecasting related costs. The application often makes only a general request for funds without providing a reasonable, well-explained justification.[16] While approving this settlement, we wish to make it clear to SDG&E and other utilities that the initial showing in the current case does not meet our requirements.[17]

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[16]Often, SDG&E simply states that "1988 base year recorded costs were adjusted as follows . . ." Although this type of explanation might help a reader to understand where the cost figures came from, it does not provide a justification. Why is it appropriate to use a 1988 base year recorded cost for this account? What changes are expected in staffing and operations? Why are the specified adjustments appropriate? How were they calculated? These types of questions should be easily answered by the initial showing.

[17] SDG&E's guarded initial showing may be a product of a protective, litigative instinct. All too often, utilities offer only the most minimal support for their rate requests, choosing instead to wait to see what subjects appear to be of interest to DRA. In response to DRA's concerns, utilities then provide focussed rebuttal.

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C. Terms of the all party settlement:

1. Electricity

1.1 Sales and Customers

In D.91-07-014, the Commission determined that the sales forecast adopted in SDG&E's 1992 ECAC proceeding should also be used for the purposes of this proceeding. The Commission adopted SDG&E's ECAC sales forecast in D.92-04-061, and that forecast is reflected in the settlement agreement.

DRA has agreed to use SDG&E's forecast of electric customers for the purposes of the settlement.

> This strategy may be traditional, but it is not acceptable. Hopefully, the company has done a more complete job of satisfying itself that a given program or expense is worthwhile. We would expect the company to make an equally convincing showing to this Commission when asking to pass those costs through rates. Where a rate case is litigated or a settlement is contested, the utility must provide a more detailed showing for all of its requested revenue requirement, in order to sustain its burden of proof. Where a settlement is adopted by all parties and is consistent with relevant law and Commission policy, the utility must provide a more detailed showing to enable the Commission to be confident both that the settlement can be well understood in the context of the company's initial request and that the Commission and its staff will have sufficient information with which to monitor the utility's activities and costs.
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> Without question, a utility seeking to encourage settlement must shed this traditional strategy and be more forthcoming with support for its request. In addition to providing information that is essential to understanding and monitoring the results of the settlement, a more complete initial showing will quicken the discovery process that is so critical to timely settlement. Because an all-party settlement obviates the need for the development (through hearings) of an extensive evidentiary record, the quality of the utility's initial showing becomes all the more important. We will reject future rate case settlements, no matter how reasonable they might otherwise appear, where they are not supported by a comprehensive initial showing.

1.2 Present Rate Revenues

The settlement adopts SDG&E's estimate of present rate revenues for the purposes of revenue allocation and rate design in this proceeding. Present rate revenues are the product of forecast sales, customers, demand, and currently effective tariffs. SDG&E's test year 1993 electric sales estimates have already been adopted by D.92-04-061 in SDG&E's ECAC proceeding.

1.3 Miscellaneous Revenues

SDG&E's forecast for test year 1993 electric miscellaneous revenues is $ 14,526,000. Electric miscellaneous revenues are those received by SDG&E in exchange for goods and services other than electric energy. This includes revenues for service establishment, returned check charges, [*29] rental of utility property, and wheeling charges.

DRA's estimate for test year 1993 electric miscellaneous revenues is $ 15,651,000. DRA auditors recommend that SDG&E recognize $ 594,000 in gains from the disposition of electric plant for test year 1993. SDG&E did not include any estimate for gains or losses in disposition of utility property in test year 1993 operating revenues. DRA auditors establish an estimate for 1993 property sales gains based on historical data from 1987 to 1990 and also reallocated recorded transactions in Accounts 411 and 421 to redistribute gains or losses between above-the-line and below-the-line accounts. The result was a recommended increase of Electric Department miscellaneous revenue of $ 594,000. DRA's miscellaneous revenue estimates were also based on its use of data more current than that which was available to SDG&E during the preparation of its general rate case application.

The level of test year 1993 electric miscellaneous revenues included in the settlement is $ 15,057,000. The settlement leaves several things in doubt. First is the nature of sales that DRA claims were inappropriately recorded in 1988 through 1991. Second is the issue [*30] of the appropriate disposition of revenues received through lease agreements as opposed to outright sales.

1.4 Production Expenses

FERC Accounts[18] 500 through 557.3 present the expenses for operation and maintenance of SDG&E's steam, nuclear, and other power production equipment and facilities. Fuel expenses that are not recovered through the ECAC, system control and load dispatch expenses, and other power production expenses are also included in these accounts.

1.4.1 Steam

1.4.1.1 Account 500 Operation, Supervision, and Engineering

SDG&E's test year 1993 estimate is $ 3,406,400.[19] The base estimate for this account was developed from an average of the 1986 through 1988 adjusted recorded expenses. A 3-year average beginning in 1986 was used by SDG&E because 1986 was the first year that the resource planning and power contract effort was charged to Account 500. The base estimate was adjusted to include $ 393,500 of environmental staff expenses and $ 1,897,400 for environment permit expenses. [*31]

DRA's estimate is $ 3,088,700. The difference is due to DRA's use of 1988 recorded expenses as a baseline and its disallowances of $ 67,500 for environmental staff and $ 58,022 in environmental permit expenses. The settlement reflects an agreed expense level of $ 3,348,378.

1.4.1.2 Account 501.2 Fuel Oil Expenses

This account contains the non-ECAC residual oil fuel handling expenses. This is an uncontested account. Both DRA and SDG&E support the company's zero-based estimate totaling $ 1,209,300.

1.4.1.3 Account 501.4 Fuel Gas Expenses

This account contains the non-ECAC portion of the gas fuel expenses. A 5-year historical average was used to develop $ 13,900 expenses estimate for the test year

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[18] "FERC Accounts" refers to standard accounts utilized by the Federal Energy Regulatory Commission. For ratemaking purposes, we define most costs by FERC account.

[19] Unless otherwise indicated, amounts are stated in 1988 dollars.

1993. DRA's estimate is $ 12,600, a difference of $ 1,300. The estimating methodologies used by the two parties yield very similar outcomes. The settlement adopts DRA's 1988 base year-derived estimate of $ 12,600.

1.4.1.4 Account 502 Operation of Boilers

SDG&E estimates its test year expenses to be $ 3,668,800. While the company has relied on an average of 1984 through 1988, DRA has relied [*32] on 1988 recorded expenses to develop its estimate of $ 3,699,000. The two methodologies produce very similar outcomes; the settlement adopts the lower of the two figures.

1.4.1.5 Account 505 Electric Operation of Turbines

SDG&E has employed a 5-year average of its recorded expenses from 1984 through 1988 to develop its 1993 estimate of $ 8,499,600. In order to ensure an adequate supply of cooling water to the South Bay and Encina Plant, SDG&E plans to dredge both the South Bay Power Plant channel and the Encina Lagoon in 1993. The South Bay dredging is estimated to cost $ 4,132,000. This channel has not been dredged since 1958. Expenses chargeable to Account 505 for dredging the Encina Lagoon total $ 219,000. DRA's estimate for account 505 is $ 5,060,700, a difference of $ 3,438,900. DRA argues that SDG&E's estimates are not supported and are therefore unacceptable. While in the past the company dredged the Encina Lagoon once every three years, it now intends to dredge annually. DRA proposes that the Encina dredging estimate be derived from recorded cost and then amortized over three years starting with the test year.

The settlement includes an agreed expense level [*33] of $ 5,681,000. DRA's proposal to amortize the cost of dredging the South Bay and related environmental cost over three years offers an appropriate way to handle large test year expenses that do not recur in the attrition years. The remaining differences relate to the appropriate methodology for forecasting the basic expense for this account, DRA's proposals to reduce SDG&E's estimated dredging expenses at both facilities and other environmental expenses. The adopted amount falls between the positions of the parties.

1.4.1.6 Account 506 Miscellaneous Expenses

SDG&E forecasts expenses reflected in this account to total $ 1,762,400. DRA expects the same expenses to total $ 1,010,600. The major cause of DRA's reduction is the decommissioning of the Heber Geothermal Plant. The parties to the settlement have agreed that the Heber expense ($ 600,000) should be deducted from the estimate for this account.

1.4.1.7 Account 507 Rents

The company and DRA agree on the adoption of SDG&E's zero-based estimate of $ 9,488,800 reflecting the annual lease payment for Encina 5 as well as leases with the Unified Port District, State Land Commission, and other miscellaneous entities. [*34] This is an uncontested account.

1.4.1.8 Account 510 Maintenance and Supervision Engineering

Parties have agreed to adopt SDG&E's uncontested estimate of $ 677,700 based on an adjusted average of 1984 through 1988 recorded expenses.

1.4.1.9 Account 511 Maintenance of Structures

Relying on a five-year average of recorded expenses beginning in 1984, SDG&E estimated its structural maintenance expenses in the test year to be $ 4,574,700. DRA's estimate, based on 1988 recorded expenses, is $ 4,755,800. For the purposes of the settlement, the parties have adopted the lower of the two estimates.

1.4.1.10 Account 512.1 Maintenance of Boilers

Once again relying on an average of 1984 through 1988 recorded expenses, SDG&E estimates test year expenses in this account totaling $ 2,393,300. DRA's use of 1988 recorded expenses derives an estimate of $ 2,111,700. The agreed-upon expense level in this settlement of $ 2,225,000 lies between the estimates of DRA and SDG&E and reflects the fact that either forecast methodology would produce reliable results.

1.4.1.11 Account 512.2 Boiler Overhaul

The settlement adopts SDG&E's estimate of $ 2,161,400 in boiler overhaul [*35] maintenance expenses for the test year. Although DRA had originally estimated expenses to be $ 241,500 lower, the settlement is reasonable in light of SDG&E's ability to demonstrate that its estimate reflects the imputed savings due to "forced outage cost charged to capital instead of O & M [operation and maintenance]". It was these savings that comprise the original difference between the parties.

1.4.1.12 Account 513.1 Routine Maintenance of Turbines

SDG&E has again utilized its actual recorded expenses from 1984 through 1988 to develop its routine turbine maintenance estimate of $ 1,213,400 for the test year. DRA's estimate, based on 1988 recorded expenses, is $ 985,400. The expense level agreed upon in the settlement is $ 1,099,000.

1.4.1.13 Account 513.2 Turbine Overhaul

The settlement adopts SDG&E's original estimate of $ 2,814,900.2.

1.4.1.14 Account 514 Miscellaneous Expenses

This account includes costs for the South Bay and Encina Lagoon dredging operations that are not reflected in Account 505. Approximately $ 500,000 of SDG&E's $ 1,260,700 estimate relates to the two dredging operations. Once again, SDG&E relied on five years of recorded expenses [*36] beginning in 1984. DRA relied on 1988 recorded expenses to derive an estimate of $ 731,200. DRA would disallow 38.94% of the dredging maintenance expenses and amortize the cost for dredging at South Bay over the 3-year rate case cycle.

The settlement adopts DRA's 3-year amortization of the South Bay dredging expenses and otherwise relies on the 5-year average methodology employed by SDG&E resulting in an adopted expense level of $ 930,000.

1.4.2 Nuclear Power

SDG&E owns 20% share of the San Onofre Nuclear Generating Station (SONGS). Its nuclear power production expenses include a 20% share of the O & M expenses for the plants as well as cost related to SDG&E's own in-house nuclear production management team.

In 1988 dollars, SDG&E's estimate for total nuclear power production expenses during test year 1993 is $ 66,855,800. SDG&E's test year estimate is based on a methodology and data presented in SCE's 1993 general case, A.90-12-018. SDG&E updated its nuclear expense estimate to reflect D.91-12-076 in SCE's general rate case application.

SCE estimated the refueling outage expenses for each year based on the average of 1987, 1988, and 1989 recorded cost in 1988 dollars [*37] for all three units. During these outages, numerous inspections, tests, equipment overhauls, preventative maintenance tests, repairs, and plant upgrades are undertaken in addition to the refueling. Based on a 90% production factor, all three SONGS units might be scheduled for refueling outages in 1993. SDG&E's share of the 1993 refueling outage costs for these units would be $ 10,598,200 in 1988 dollars.

The actual timing for refueling outages of the various units will be affected by the performance of the units. If the production factor is greater or less than the assumed 90% value for any given unit, its refueling outage schedule would be advanced or delayed accordingly. Since Unit 2 is scheduled for refueling in the third quarter of 1993 and Unit 3 is scheduled for refueling outage in the fourth quarter of 1993, a schedule change could cause all or portions of the refueling outage expenses to be incurred in a different calendar year than originally planned. For this reason, SCE had requested implementation of a "flexible outage schedule" in its 1993 general rate case. By means of an attrition advice letter, adjustments can be made for changes in the refueling schedule. [*38] SDG&E asked that it also be allowed to handle refueling outage schedule changes through an attrition advice letter.

SDG&E has a nuclear department consisting of a manager, two senior engineers, two engineers, and a secretary. One of the senior engineers is stationed at SONGS. The department allows SDG&E to monitor and evaluate SONGS activities as well as to coordinate the company's SONGS involvement. According to SDG&E, the company's nuclear department personnel actively participate in the various SONGS working groups and provide information to the company's senior management so that they are well equipped to respond to SONGS-related issues. In 1988 dollars, the test year 1993 estimate for SDG&E's nuclear department expense is $ 503,600.

DRA estimates SDG&E's test year nuclear expenses to be $ 57,795,000. This represents a $ 7,063,000 difference from the company's estimate. DRA reports that its differences are due primarily to the following:

1. Use of a different forecasting methodology to derive a base year estimate.

2. Removal of 2% gross added to SDG&E's calculated share of SCE's SONGS expenses. DRA objected to SDG&E's adding 2% gross onto the base O & M and refueling [*39] estimate. DRA argues that SDG&E misinterpreted the Commission decision to include real growth in the attrition years 1993 and 1994 for SCE. SCE was only allowed to adjust for real growth through 1992. There was no growth allowance for 1993 and 1994.

3. The choice of labor and nonlabor escalators used to calculate SDG&E's share of SCE's SONGS expenses.

DRA objected to the company's using its own labor and nonlabor escalation rates for the purposes of escalating SONGS expenses. DRA believes that SCE's escalation rates are more appropriate to use since SCE is the operator of the plant.

4. A reduction in the number of nuclear refuelings in the test year.

In D.91-12-076, the Commission recognized only one refueling outage for SONGS in 1993. While agreeing that SCE and SDG&E should be allowed to reflect refueling outage schedule changes in advice letter filings, to date, no such filing has been made by either company. DRA argues that it is therefore appropriate to forecast expenses in 1993 for only one refueling outage.

5. SDG&E's nuclear department expenses.

SDG&E's nuclear department expenses reflect the only portion of SDG&E's nuclear expenses which are not tied to the [*40] SCE general case decision. DRA argues that the SDG&E nuclear department should undergo some reduction in size in anticipation of the shutdown of SONGS Unit 1. However, DRA makes no specific recommendation for reduction in expenses for the nuclear department.

In the settlement, the parties agreed to adopt DRA's expense estimate, after making a $ 79,000 adjustment to reflect errors related to Nuclear Regulatory Commission (NRC) fees. The settling parties do not propose that SDG&E's nuclear department staffing be reduced.

The settling parties recommend that SDG&E be afforded in its attrition filings the same ratemaking treatment given to SCE. This would allow SDG&E to recover its expenses for each of the refueling outages identified by SCE in its 1993 attrition year advice letter. In addition, the parties asked that the company's estimated expenses be adjusted to reflect changes in NRC fees which might become effective prior to the issuance of the revenue requirement decision. These recommendations are reasonable, as they will provide for consistent treatment between the two major partners at SONGS.

1.4.3 Accounts 546 to 557 Gas Turbine Power and Other Power Supplies [*41]

SDG&E has used a series of 1988 base year and zero-based methods for forecasting test year expenses related to gas turbine and other power supplies. The expense categories, here, relate to maintenance, overhaul of gas turbines, system control, and load dispatching as well as the portion of power control, resource planning, power contracts, and Mexican project department expenses related to present and possible future power purchases. From the outset, SDG&E and DRA have agreed that an expense estimate of $ 2,393,200 is reasonable for the test year. The parties have adopted this figure for use in the settlement.

1.5 Electric Transmission Expenses

Transmission operations are comprised of work functions associated with dispatching, monitoring, and power control operations for the transmission system. Transmission maintenance includes expenses associated with substation and transmission line maintenance, insulator washing and degreasing, substation breaker and relay maintenance, repair of damaged facilities, grounds keeping, and expenses associated with capital project construction.

1.5.1 Account 560 Operations, Supervision and Engineering

This account includes the [*42] cost of labor and other expenses incurred in the general supervision of the operation of the transmission system. Both SDG&E and DRA derive the estimates for this account by adjusting 1988 recorded costs to reflect a pattern of lower expenditures for information services, building services, and a lower level of labor. Both parties agree on the resulting expense forecast of $ 885,300, which is also adopted for the purposes of the settlement.

1.5.2 Account 561 Load Dispatching

For the purposes of this account as well, SDG&E and DRA agree on the use of adjusted 1988 recorded cost. The resulting test year estimate is $ 1,334,000. This number is also adopted in the settlement.

1.5.3 Account 562 Station Expenses

This account includes the cost of labor, materials used, and expenses incurred in the operation of transmission substations and switch stations. SDG&E's estimate for this account is based on 1988 recorded data and includes an increase of $ 81,200 for landscaping expenses at the Penasquitos substation. The company argues that these added landscaping expenses were needed in order to comply with the the conditional use permit and for additional water usage as a [*43] result of expansion of the substation in 1991. After a tour of the Penasquitos site, DRA staff concluded that the added expenses were not required because from all appearances, the landscaping is complete. In addition, DRA argues that ratepayers should not be responsible to pay expenses related to additional water use after five years of drought in California, and that it is SDG&E's responsibility to install drought-resistant, low maintenance landscaping.

The settlement adopts SDG&E's original figure of $ 397,200.

1.5.4 Account 563 Overhead Line Expenses

SDG&E and DRA agree that the cost of labor, materials, and expenses incurred in the operation of overhead transmission lines is estimated to be $ 513,600. Appropriately, this figure has been adopted in the settlement as well.

1.5.5 Account 566 Miscellaneous Transmission Expenses

This account includes the cost of labor, materials used, and expenses incurred in transmission maps and records work, transmission office expenses, and other transmission expenses not provided for elsewhere. SDG&E relied on 1988 recorded expenses of $ 1,052,100 and adjusted that number upwards to produce a test year estimate of $ 1,668,600. [*44] Historically, some of the expenses from various operating departments have been charged to administrative and general (A&G) accounts. SDG&E has transferred some of these costs to Account 566 and adjusted A&G Accounts 920 and 921 accordingly.

An additional adjustment of $ 222,500 was included in this account for three engineers and related transportation, computer equipment, and travel costs. According to SDG&E, the additional personnel are needed to respond to and participate in various federal, state, and industry-sponsored initiatives on transmission access, and state and regional transmission planning. SDG&E anticipates additional work related to the emerging FERC rules on wheeling and case-by-case market pricing, and the increasing role of the CEC in the transmission planning process. In addition, SDG&E anticipates that proposed changes to General Order 131D, pertaining to new transmission lines under 200 kV, may place new burdens on SDG&E's internal planning process.

DRA recommends disallowing one-half of SDG&E's estimate for additional engineers, producing a test year revenue requirement of $ 1,557,350, arguing that SDG&E has not demonstrated the need for senior engineers [*45] as opposed to entry level staff positions to fulfill any increased responsibilities. The settlement adopts DRA's lower estimate.

1.5.6 Account 567 Rents

DRA and SDG&E agree that rents for properties used, occupied, or operated in connection with the transmission system, including payments to the U.S. government and others for use of public or private lands and reservations for transmission line rights-of-way should be forecasted at the level of $ 496,800. Both the company and DRA have estimated future cost increases under the various lease agreements, based on an analysis of lease terms. The analysis of DRA and SDG&E both support this result.

1.5.7 Accounts 586 to 573 Maintenance

In each account related to transmission maintenance, DRA's use of 1988 recorded year data produces a similar test year forecast to that derived from SDG&E's five-year average analysis. Where differences exist between the estimates of the parties, the settlers erred on the side of using the lower estimate derived from DRA's work, producing the following results:

Account 568 Maintenance, Supervision, and Engineering - $ 146,700;

Account 570 Maintenance of Station Equipment - $ 1,769,000; [*46]

Account 571 Maintenance of Overhead Lines - $ 1,982,100

Account 572 Maintenance of Underground Lines - $ 7,100

Account 573 Maintenance of Miscellaneous Transmission - $ 8,400

1.6 Electric Distribution

Electric distribution expenses are those incurred in operating and maintaining the company's electric distribution system. These costs include labor, material, engineering, supervision, and other expenses associated with the operation and maintenance of distribution substations and structures, overhead and underground lines, and associated equipment.

SDG&E and DRA both estimated the distribution accounts based on 1988 recorded expenses.

1.6.1 Operation, Supervision, and Engineering

SDG&E requested $ 3,773,700 for test year 1993. The company adjusted baseline 1988 recorded expenses by including $ 290,000 transferred from customer accounts, $ 241,500 for project management specialist training classes, $ 588,600 for increased information services usage and labor, and $ 1,175,100 for Distribution Planning and Scheduling System (DPSS) enhancements. According to the company, these enhancements will allow the completion of a project to interface PG&E's two primary automated [*47] distribution planning systems: DPSS and the Distribution Facilities Information System (DFIS).

DRA's estimate is $ 2,598,600 reflecting DRA's suggestion that increases related to DPSS enhancements not be allowed. DRA argues that SDG&E has not sufficiently documented the benefits of the interface project. The settlement adopts the figure of $ 3,187,000, a figure that includes one-half of SDG&E's estimate for DPSS enhancements.

According to SDG&E, the Distribution Planning and Scheduling System provides a common information base to be used by management planners, designers, and construction personnel. DPSS is a totally integrated management system that supports work order development, construction, maintenance, and project accounting for electric and gas distribution activities. The system also automates major portions of the planning, cost estimating, scheduling, tracking, reporting, cost analysis, and performance measurement processes. The Distribution Facilities Information System is another data base system designed to provide timely, accurate information concerning the company's distribution system. DFIS produces electric maps from the data base as well as performing engineering [*48] and property accounting functions.

The purpose of DPSS is to work with the DFIS to assure more efficient utilization of SDG&E's existing distribution network. SDG&E states that its primary goal in using DPSS is to reduce its capital expenditures.

SDG&E began installing the DPSS system in 1989, early in the SCE merger process. It discontinued DPSS activities while the merger was pending. Through a data request, DRA asked the company for a cost-benefit analysis justifying the DPSS enhancements it now is requesting. In response, SDG&E produced a 1986 cost-benefit analysis for the DPSS project. According to DRA, this analysis did not assume any post-implementation cost. DRA argues that in light of all of the changes experienced by SDG&E since 1986, the cost-effectiveness analysis is seriously out of date. Although the company has provided a description of its goals in implementing the DPSS enhancements, it has not offered information sufficient to overcome the legitimate concerns raised by DRA.

1.6.2 Account 581 Load Dispatching

This account includes the cost of labor, materials used, and expenses incurred in load dispatching operations pertaining to the distribution [*49] of electricity. In their testimony, SDG&E and DRA agree that expenses during the test year for this purposes should be forecast to be $ 856,100. This is derived from a 1988 base of $ 881,700 and a downward adjustment of $ 25,600. The adjustment reflects the elimination of two supervisors in distribution control and an increase of $ 12,500 for the operations portion of a switching center operator. The settlement adopts the uncontested figure.

1.6.3 Account 582 Station Expenses

This account includes the cost of labor, materials used, and expenses incurred in the operation of distribution substations and switching stations. SDG&E's estimate of $ 2,522,500 is derived from the 1988 base of $ 1,846,300 and three adjustments totaling $ 676,200: increased hazardous waste handling costs, additional landscape maintenance cost of substation facilities, and a change in accounting related to some capital projects. DRA would reduce this amount by $ 262,700 by eliminating increases requested for landscaping and water costs and by reducing hazardous waste handling cost/fees by $ 137,000.

The settlement adopts DRA's estimate of $ 2,259,800.

1.6.4 Overhead and Underground Line Expenses [*50]

Relying on 1988 recorded data, SDG&E and DRA agree on a test year expense forecast of $ 1,638,100 for overhead line expenses and $ 1,260,700 for underground line expenses. The settling parties adopt these uncontested figures.

1.6.5 Account 585 Streetlighting and Signal System Expenses

Functions charged to this account include patrolling for streetlight lamp outages, lamp replacements, and glassware replacements. The uncontested estimate contained in both SDG&E and DRA's testimony is $ 216,700. This amount has been reflected in the settlement as well.

1.6.6 Account 586 Meter Expenses

This account includes the cost of labor, materials used, and expenses incurred in removing, resetting, and relocating meters and equipment, as well as cost incurred for meter tests, meter records, and turn-ons and shut-offs. SDG&E has relied on 1988 recorded expenses, with adjustments, concluding that 1993 test year expenses should be $ 3,532,200. The adjustments to the 1988 figures are intended to reflect the impact of customer growth, changes in the meter testing area, expanding programs to enhance customer satisfaction, and implementation of a field order control system. DRA opposed [*51] the inclusion of two items totaling $ 302,600: expenses related to the Field Service System and improvements designed to provide two-hour appointment windows for Turn-On-Meter workers.

According to DRA, the purpose of the Field Service System is to place mobile data units in company vehicles to allow SDG&E field personnel to quickly and more easily communicate their capability to initiate and close orders. Expenses related to this program which are included in Account 586 are only a small portion of a total program cost, most of which would be capitalized. DRA reports that during a field investigation in January 1992 SDG&E acknowledged that this project is still in the developmental stage and that the company is still trying to determine if it wants to continue with the project.

The additional Turn-On-Meter workers would be added to allow for the scheduling of appointments within a two-hour period. SDG&E reports that surveys indicate their customers want this service improvement. DRA reports, however, that it reviewed available survey results and found no indication that customers had even mentioned such a feature. DRA argues that the highest customer concern is for the reduction [*52] of rates and that accordingly, the request for additional Turn-On-Meter workers should be denied.

The settlement would adopt DRA's estimates for Account 586. Due to the company's apparent uncertainty concerning the Field Service System, it is reasonable to delete the company's currently requested funding. Although the record also supports denial of SDG&E's initial request for additional Turn-On-Meter workers, we remain concerned that the company not be deterred from taking relatively low-cost steps that are likely to improve service. We anticipate that the company and DRA will reconsider this proposal in the context of SDG&E's next general rate case.

1.6.7 Account 587 Customer Installation Expenses

This account includes costs related to investigating service complaints and rendering services to customers. DRA and SDG&E have both relied on adjusted 1988 recorded costs to produce an estimate of $ 1,926,700. The adjustments primarily reflect costs related to staffing an electromagnetic fields (EMF) center. The purpose of this center is to respond to requests of SDG&E's customers for information on EMF-related issues. The nine part-time EMF representatives and one full-time [*53] scheduler assigned to this center follow up leads generated by customer contact employees by making field visits, taking EMF measurements, and discussing issues and findings with customers. The proposed budget also reflects an upward adjustment of $ 41,500 to accommodate customer growth. For the purposes of this settlement, the parties adopt this uncontested estimate.

1.6.8 Account 588 Miscellaneous Distribution Expenses

This account includes all costs incurred in the preparation and preservation of maps and records of the company's electric distribution system. The settlement adopts SDG&E's 1993 test year estimate for this account of $ 4,926,400. In the 1988 base year, a cost in this account would heavily be affected by conversions to the DFIS system. In order to develop a more typical year's budget, SDG&E relied upon 1991 recorded expenses, adjusted upward to reflect enhancements to DFIS and the implementation of an Outage Management System (OMS).

In its testimony, DRA proposed removing expenses related to OMS and the DFIS system enhancements, totaling $ 793,200. DRA's concerns related to DFIS enhancement expenses seems to stem from the staff's assumption that DFIS [*54] and DPSS are interdependent systems. In that DRA suggested that DPSS-related costs be excluded from Account 580, it has also proposed disallowance of DFIS enhancement costs here. SDG&E argues, however, that while the two programs are complementary, they are not interdependent. SDG&E's witness Lee Schavrien stated, at Tr. pp. 351 and 352, as follows:

"The DFIS project has been around for a long time and it's essentially an electronic mapping project, mapping out the streets, the services that are available and underground services and the overhead services.

"The DPSS project is essentially a work order project for distributing project work orders for either new service or maintenance that facilitates that. The DPSS project uses information from the DFIS, but is not dependent on it. It helps facilitate the information faster.

"So they are distinctly two different projects and they distinctly have two separate enhancement programs that link together for certain projects or issues that have to be that way."

SDG&E's funding request for the OMS has both an expense and a capital component. Within Account 588, SDG&E includes $ 353,100 for the OMS system. In addition, SDG&E would [*55] book $ 2,018,000 as a plant addition in 1993. Testifying for SDG&E, Michael E. McNabb states that:

"This project will enable information to be processed faster during system disturbances, allowing more efficient management of company resources and reducing restoration times. One of the major issues with our customers, particularly commercial/industrial customers, is the need to have information during system outages. OMS will help us meet this corporate goal . . ."

Testifying on behalf of DRA, Clayton K. Tang comments that:

"SDG&E predicts that this project will reduce the average outage by about 5 to 10 minutes. Yet a recent survey showed that SDG&E's customers are already quite satisfied with SDG&E's level of reliability. DRA believes that the project is unnecessary at this time."

While asserting that OMS will enable the company to process information faster during system disturbances, Mr. McNabb and the company had provided the Commission with no evidence demonstrating how the system would deliver its promise. The company asserts that the need for better information during a system outage is acutely felt by at least some of its customers. The company's own survey results [*56] did not seem to support that conclusion. SDG&E claims that OMS will help the company meet its corporate goal of improving service to customers, but does not provide information which will help the Commission determine whether this particular program is a cost-effective way to improve service to customers.

We want to find ways to encourage the company to improve its service wherever it is reasonable and cost-effective to do so. With the limited information provided to the Commission, the OMS program sounds like a promising addition. However, OMS does not represent an insignificant expenditure. Over three years, the program would incur expenses of approximately $ 1 million while adding over $ 2 million to the company's rate base. Hopefully, the company has done a more complete job of satisfying itself that commitment to the OMS program is worthwhile. We would expect the company to make an equally convincing showing to this Commission when asking to pass those costs through rates.

1.6.9 Rents

The settlement adopts the uncontested SDG&E 1993 test year estimate of $ 113,300 for rents related to properties used, occupied or operated in connection with the distribution system. [*57]

1.6.10 Accounts 590 to 598 Maintenance

The settlement adopts the uncontested estimate of $ 323,500 for expenses in Account 590, related to maintenance, supervision, and engineering. In addition, it adopts the uncontested estimate of $ 40,900 for the cost of labor, materials used, and expenses incurred in the maintenance of structures as reflected in Account 591.

SDG&E requests $ 1,588,600 for the cost of labor, materials used, and expenses incurred in maintaining station equipment as recorded in Account 592. This estimate is derived from a 1988 base of $ 1,357,800 and an adjustment of $ 230,800 for system growth. Mr. McNabb, testifying for SDG&E, states that:

"Growth was calculated by determining the increase in the number of breakers in service from 1988 to 1990. The number of distribution breakers in service was selected because they are a good indicator of the overall requirement for distribution substation maintenance. Yearly compounded growth of 3.2% was applied to the five-year period from 1988 to 1993 for an overall growth of 17%."

DRA originally proposed adopting a budget of $ 1,357,800. The difference is due to DRA's removal of increases requested for growth. [*58] DRA argued that historical expenses from 1984 to 1988 suggest that this account does not track with system growth. On that basis, DRA recommended use of 1988 recorded expenses.

For the purposes of the settlement, the parties adopt of DRA's recommended expense level.

SDG&E proposed an expense level of $ 8,774,100 for overhead line maintenance expenses. DRA originally proposed adjusting this amount by $ 702,200 to reflect the removal of increases requested for additional tree trimming ($ 451,300), a correction to a mathematical estimate for damage caused by the general public ($ 62,800), and an adjustment of estimated maintenance associated with capital ($ 188,100).

The settlement adopts an expense level of $ 8,486,000. This amount reflects SDG&E's estimate, adjusted as proposed by DRA with the exception of approximately one-half of the funding request related to additional tree trimming. The settling parties explain that DRA's original proposal contained an error. With respect to tree trimming, SDG&E states that it was seeking to maintain a two-year trimming cycle. One-half of the funding request is included in the settlement agreement to facilitate this cycle.

SDG&E requests [*59] $ 3,965,200 for maintenance of underground lines (Account 594). The company states that it derives this estimate from a 1988 base of $ 2,155,600 and net adjustments totaling $ 1,809,600. Most of the increase from base year expenses reflects a new strategy for preventive maintenance of underground distribution lines. Historically, SDG&E performs preventive maintenance activities on a ten-year cycle, resulting in base year expenses of $ 631,900. The company proposes changing to a three-year preventive maintenance cycle, resulting in test year expenses of $ 2,326,300 (an increase of $ 1,694,400).

DRA suggests that a change from a ten-year cycle to a three-year cycle is "too drastic a change to be taken at once." DRA instead suggests a more moderate change to a six-year inspection cycle, resulting in a preventive maintenance budget of $ 1,240,300. Mr. McNabb, testifying for the company, states that:

"Experience with this lengthy cycle has taught us that a ten-year interval is far too long to maintain the system in proper operating condition. Extensive and unrepairable corrosion is a major issue."

SDG&E hopes that this change will reduce capital cost for replacement equipment [*60] and contribute to the corporate goal of improved electric reliability by reducing outages. However, SDG&E acknowledges that it cannot predict the extent to which outages will be reduced as a result of these increased maintenance activities.

For the purposes of the settlement, parties adopt an expense level of $ 3,192,000, reflecting a resolution of the preventive maintenance question that lies somewhere between SDG&E's proposed new three-year cycle and DRA's proposed alternative six-year cycle. This reflects both the uncertainty as to the appropriate preventive maintenance cycle to adopt and the need to test the results of an accelerated preventive maintenance program before reaching a conclusion about the ultimate cycle to adopt. As Mr. McNabb testified, the effects of changing the preventive maintenance cycle will not be clear until the first new cycle is completed. Thus, it is now unlikely that SDG&E will have any significant findings to report on the effects of its new strategy in time for the next general rate case. We will expect SDG&E to provide a detailed report for the general rate case following the completion of the newly adopted cycle.

Account 595 includes the cost [*61] of labor, materials used, and expenses incurred in maintaining overhead and underground distribution line transformers and voltage regulators. SDG&E asked for $ 590,100 for the 1993 test year. In the settlement, parties agree to adopt DRA's proposed reduction of $ 54,000 to reflect adjustments in Account 594 for the preventive maintenance schedule.

SDG&E and DRA agree that $ 241,900 should be included for expenses in Account 596, related to the cost of maintaining equipment use for public street and highway lighting systems. This uncontested figure is reflected in the settlement proposal as well.

The parties also agree on forecasts for costs related to maintenance of meters ($ 907,800), and maintenance of miscellaneous distribution plant ($ 30,700). These amounts have been reflected in the settlement proposal.

1.7 Customer Accounting and Collections

As the settling parties explain in the joint comparison exhibit, customer accounting and collection expenses include amounts related to activities such as: meter reading, billing, processing of an accounting for customer payments, handling customer orders, processing customer telephone inquiries, collections, and meter revenue [*62] protection. Postal expenses incurred in the mailing of customer bills and uncollectible write-offs are also included in this group of accounts. Costs are estimated on a total company basis, then allocated to electric operations, gas operations, and steam operations based on the number of customers in each department, with extra weight being given to customers requiring special handling. The electric department allocation is estimated to be 64.73% for test year 1993. The allocations for gas and steam departments during the test year are estimated to be 35.26% and 0.01%, respectively.

1.7.1 Account 901 Supervision

SDG&E used 1988 recorded expenses of $ 322,000 to derive at a 1993 test year estimate of $ 288,000 for this account. Adjustments to this base include an increase of $ 30,000 for customer growth net of productivity and a decrease of $ 64,000 due to transfers to the gas and electric transmission and distribution accounts. DRA recommends that the $ 26,200 proposed for customer growth net of productivity be excluded as unjustified because supervision at the Account 901 level does not vary directly with changes in customer accounts. For the purposes of the settlement, [*63] the parties agree to adopt DRA's adjustment.

1.7.2 Account 902 Meter Reading

SDG&E's test year estimate of $ 4,934,000 for this account is derived by adjusting the 1988 recorded expense of $ 3,390,000 by including an increase of $ 475,000 for customer growth net of productivity, an increase of $ 253,000 for the replacement of the existing hand-held meter reading system and its associated data processing costs, an increase of $ 18,000 to provide mechanized reading capability for the internal data processors now being used, an increase of $ 220,000 for meter reading staff support and auditing, surveying and rerouting of accounts, an increase of $ 58,000 for the initial phases of moving to an automated meter reading system, and a decrease of $ 21,000 for transfers to Account 901. DRA recommended a reduction of $ 382,490 for some of the projects because of apparent overlap between the specific projects and others which would normally be funded within the growth-justified increase. The settlement includes a recommendation that a figure of $ 4,714,000 be adopted.

This account includes labor and other costs associated with answering customer telephone inquiries concerning applications [*64] for service, disconnections, transfers, meter tests, contracts, collections, and billings. SDG&E relies on 1988 recorded expenses of $ 6,112,000 in reaching its 1993 test year estimate of $ 8,850,000. Adjustments to the 1988 base include an increase of $ 820,000 for customer growth, an increase of $ 406,000 for upgrading and training of telephone center personnel, an increase of $ 198,000 for 24-hour operation of the telephone center, an increase of $ 1,233,000 for the implementation of new customer service programs, an increase of $ 269,000 in data processing costs in excess of the customer growth component, and a decrease of $ 188,000 for transfers to the gas and electric transmission and distribution accounts.

DRA recommends excluding $ 1,151,600 from SDG&E's forecast. The staff argues that "The growth factor less productivity is not appropriate for Account 903.1." It is not clear what was meant by this argument and DRA provided no additional discussion to explain its point. In addition, DRA argues that SDG&E's estimate includes a duplicative $ 79,800 expenditure for a new business office proposed for Encinitas. Further, DRA would disallow $ 66,700 for a customer services [*65] records update program that it argues should be considered in Account 903.4. Finally, DRA proposes that SDG&E's requested funding for 24-hour customer service not be allowed.

DRA argues that 24-hour customer service is not justified for this gas and electric utility. DRA argues:

"Banks and groceries have 24-hour customer service as a marketing program to attract customers from other banks. SDG&E customers can choose between hundreds of banks, but only one energy utility. Customer service needs from energy utilities is quite different from other industries having greater customer contact like banks and groceries. The customer service survey which intends to measure customer satisfaction is subject to interpretation, and DRA recommends that SDG&E not add costly programs simply because some customers polled indicate that the item would be nice to have."

The proposed settlement adopts a budget of $ 8,430,000 for this account, dismissing the differences in positions between SDG&E and DRA as being "based largely on a dispute over estimating methodology."

1.7.4 Account 903.2 Credit Management

SDG&E and DRA agree that it is reasonable to forecast expenses of $ 455,000 during [*66] the test year.

1.7.5 Account 903.3 Collections

SDG&E relied on the 1988 recorded expense of $ 1,759,000 in deriving its test year estimate of $ 2,227,000. DRA agrees with this estimate. In addition, DRA recommends continued participation by SDG&E in the California Utility Exchange (CUE), a joint project among California energy utilities to maintain a common data base of new customers and delinquent customers for all utilities. SDG&E, Southern California Edison, Los Angeles Department of Water and Power, Pacific Gas and Electric Company, and Southern California Gas Company are major participants in the CUE project. DRA reports that SDG&E has its own internal customer matching program that identifies customers who have relocated within the SDG&E service area without paying a closing bill. The staff argues that although SDG&E's internal program reduces the potential benefit from the CUE participation, SDG&E should continue to participate in the CUE project providing that it is generally cost-effective. Continuing participation by SDG&E will also benefit other CUE participants by improving the information base.

The settlement adopts the uncontested test year forecast for [*67] this account. In addition, the settling parties agree to continue participation by SDG&E in the CUE program, providing that it remains cost-effective.

1.7.6 Account 903.4 Customer Payments

The settlement adopts DRA's estimate of $ 1,199,000 for this account. This represents a $ 43,175 reduction of SDG&E's proposed budget of $ 1,242,000 due to customer service representative salary upgrades which DRA argues should have been included in growth projections.

1.7.7 Account 903.5 Billing and Bookkeeping

The settlement adopts SDG&E's estimate of test year expenses totaling $ 2,055,000. DRA had argued in its testimony that $ 233,675 in savings resulting from newly capitalized projects were not reflected in SDG&E's estimate. SDG&E argues to the contrary.

Joel Lubin, testifying for DRA, states that savings resulting from newly capitalized projects are not included, but never explains how he reached that conclusion. In the joint comparison exhibit, SDG&E simply responds that its estimate "does reflect savings from newly capitalized projects." However, SDG&E provides no evidence to support this conclusion.

1.7.8 Account 903.6 Data Processing

This account reflects [*68] costs associated with the use of computers by customer service personnel to keep track of customer accounts, records, and collections. SDG&E proposed adjusting the 1988 recorded expense of $ 1,795,000 to reflect customer growth by adding $ 177,000 to the forecast for this account. For the purposes of the settlement, the parties agreed to stick with the 1988 recorded expense level as was advocated by DRA in its original testimony.

1.7.9 Account 903.7 Postage

The postage costs reflected in this account relate to the mailing of customer bills, collection notices, and other correspondence. Without explaining how it derived that number, SDG&E has requested $ 2,442,000 for postage. The settling parties agreed to adopt DRA's recommended postage level of $ 2,358,000. In support of this recommendation, the settling parties included a table demonstrating how the postage estimates were calculated. This table is included as Appendix C to the settlement agreement. The record supports adoption of a company-wide estimate of postage expenses equaling $ 3,643,044.

1.7.10 Account 903.8 Energy Theft

Costs included in this account relate to the investigation and prosecution of energy [*69] theft cases. SDG&E proposed adjusting the 1988 recorded expense of $ 213,000 to reflect customer growth, resulting in a 1993 estimate of $ 237,000 for this account. DRA recommends simply carrying forward the 1988 recorded expense level, arguing that these expenses do not vary directly based on the number of customers. The settlement adopts DRA's position.

1.7.11 Account 903.9 Customer Service Conservation LIRA Programs

SDG&E asks for $ 332,000 and states that this estimate was developed "on a program-by-program basis." For the purposes of the settlement, the parties have agreed that these expenses would be deferred for review in the reasonableness portion of the ECAC and Biennial Cost Allocation proceedings (BCAP).

1.7.12 Account 904 Uncollectible Accounts

SDG&E developed a 1993 estimate of $ 2,932,000 by applying an uncollectible factor of 0.287% to the estimated revenues. The uncollectible rate is developed by use of an econometric model. DRA recommends using a rate of 0.274% which it states reflects inclusion of year-end 1991 data in the company's model. The settlement includes a recommendation that DRA's uncollectible rate be applied, producing an expected [*70] uncollectible expense for 1993 of $ 2,578,000. In that DRA's recommendation is based on more recent data, the record supports the adoption of this approach.

1.7.13 Account 905 Miscellaneous Customer Accounts Expense

This account covers expenses not provided for elsewhere. In its testimony, SDG&E forecasts expenses of $ 89,000, without identifying what these expenses are. The sole support for SDG&E's position is that its recorded expenses in 1988 were $ 80,000. DRA recommends that the 1988 recorded expense level be carried forward without adjustments to reflect customer growth. This approach is adopted in the settlement as well.

1.8 Electric Marketing Expense

SDG&E's initial estimate for expenses in its marketing accounts totals $ 46,843,000. These expenses can be divided into three main categories: (1) DSM, (2) energy services, and (3) electric vehicles. Expenses related to DSM programs were not part of the settlement agreement. The settling parties have agreed to defer consideration of EV electric vehicle marketing program costs to the low emission vehicle investigation, I.91-10-029. The discussion, here, is limited to Account 912 as it relates to SDG&E's [*71] Major Account Executive program.

SDG&E assigns account executives to major commercial and industrial customers to provide assistance with all their energy service needs. In the past, SDG&E has allocated what it considers to be an appropriate portion of these expenses to its DSM program accounts. The activities at issue include providing customers with assistance related to billing and rate questions as well as advice about business operations affecting energy usage, assisting governmental customers with all energy services, and assisting customers with power quality problems and analyses. Support activities for these efforts are also included.

The company reports that it has provided these services to customers for several years. In the public participation hearings held in this docket, numerous representatives of businesses in SDG&E's service territory provided testimonials praising the account executive program. The company proposes a budget for 1993 comparable to what it expects its actual expenses to be for this program in 1992.

In its testimony, DRA argued that the cost of providing special attention to particular customers should not be borne by ratepayers. In addition, [*72] DRA points out that similar activities are already funded by ratepayers either through the DSM programs (energy issues) or through customer accounts (billing and rate issues). "DRA thinks this special attention is provided to enhance public relations or elicit good will rather than to merely provide informational services. The Commission has consistently rejected requests for ratepayer funding of activities designed to enhance public relations or elicit good will." DRA cites D.84902 *(78 CPUC 638)* for the proposition that the Commission disallows public relation expenses which, among other things, cannot be shown to encourage "the more efficient operation of the utility's plant, the more efficient use or presents services, or the conservation of energy or natural resources, or present accurate information on the economical purchase, maintenance, or effective use of electrical or gas supplies or devices." On this basis, DRA suggests that the only legitimate expenses of this nature would be related to conservation activities and that expenses for such activities should be reflected in DSM accounts. Thus, DRA recommends that the Account Executive program expenses listed in Account [*73] 912 be disallowed for ratemaking purposes.

In the settlement agreement, the parties propose that SDG&E receive revenue requirement including $ 1,620,000 for the Major Account Executive program. In support of the settlement, the parties argue that in 1987, when SDG&E created its major accounts marketing section, that section had as its primary objective preventing bypass by large customers. A portion of the costs of such services were charged to Account 912. They report that as SDG&E's rates have decreased and DSM programs expenditures have increased, the focus of Account 912 expenses has become resolving bill inquiries and providing other customer services for SDG&E's large customers. While these expenses are not part of SDG&E's DSM programs, SDG&E's request for funding through Account 912 rather than Account 903 led to the impression that these expenses are related to DSM programs. The parties argue that in fact they are not related to DSM. Given the current focus of energy activities, the settling parties agree that for future periods, SDG&E will charge the costs of customer service for large customers to Account 903.

1.9 Administrative and General

A&G expenses are [*74] those that are not easily attributable to specific functional areas. Such costs are recorded in FERC Accounts 920 through 935 and subsequently allocated to electric, gas, and steam departments. They include the majority of salaries and expenses of general office personnel, including officers, not chargeable to a specific functional area. A&G accounts include charges for insurance, casualty payments, consultant fees, employee pensions and benefits, franchise requirements, research and development expenses, general office rents and maintenance, regulatory expenses, association dues, and securities and bank expenses. For most A&G accounts, the parties have relied on what they describe as a widely accepted method for deriving the allocation percentages to apply to the distribution of A&G expenses, resulting in an allocation of 74.56% to electric, 25.19% to gas, and 0.25% to steam. The exceptions are expenses in Account 925 (injuries and damages) which are allocated based on a historical trend of direct charges to each department, and Account 926 (employee pensions and benefits) which are allocated on the basis of direct operating and maintenance labor.

1.9.1 Account 920 A&G [*75] Salaries

Account 920 includes salaries and compensation for employees of all organizations that are not specifically provided for in other functional accounts. Starting with 1988 recorded expenses, SDG&E states that it first subtracted $ 1,400,000 to reflect "accounting adjustments and non-A&G charging" and then added $ 980,000 for positions that were "added in resource planning, pricing, legal, and human service areas reflecting new functions and regulatory requirements." The total proposed budget estimate is $ 19,333,000. SDG&E has not provided evidence as to how many positions it is adding under any of the listed categories, how much the new employees will be paid, or why any and all of the new positions are necessary. This account also would include funds for a long-term incentive compensation plan ($ 714,000), an executive incentive compensation ($ 703,000), and a senior management incentive compensation plan ($ 220,000).

DRA recommends an electric department Account 920 expense level of $ 17,653,000, reflecting a difference of $ 1,680,000. This difference results from DRA's proposal that all expenses related to incentive compensation program plans be borne by shareholders, [*76] not ratepayers. In addition, DRA would disallow $ 43,000 which is designated to reflect merger-related labor. For the purposes of the settlement, the parties propose removing from the Account 920 forecast all costs related to the Long-term Incentive Compensation and Executive Incentive Compensation Plans. The proposed settlement does include revenues for the Senior Management Incentive Compensation Plan (apparently, at a level of $ 127,000).

1.9.2 Account 921 Office Supplies and Expenses

SDG&E seeks $ 10,089,000 for office supplies and expenses that are not specifically provided for in other functional accounts. The company developed its estimate starting with 1988 recorded expenses which are first reduced by $ 1,400,000 to reflect accounting adjustments (which are never explained) and then increased by $ 2,570,000 for increased expenses "primarily for information systems staff and related expenses of new personnel . . ." The nature of these expenses is also never explained. DRA is of the opinion that there is a close relationship between expenditures for salaries (reflected in Account 920) and those for office supplies and expenses (as reflected in this account). The [*77] staff found that on average, over a five-year period, the office supplies and expense level has equaled 52% of the A&G salary expense level reflected in Account 920. Applying this ratio, DRA derived a forecast expense level for Account 921 equal to $ 9,194,000 ($ 895,000 less than SDG&E's estimate).

SDG&E and DRA disagree on the use of this methodology. The settlement proposes adoption of $ 9,627,000, reflecting a compromise between the original positions of the parties.

1.9.3 Account 922 A&G Expenses Transfer-Credit

This account captures the portion of expenses recorded in Accounts 920, 921, and 926 that is transferred to construction. For the purposes of determining these transfers, an annual study is undertaken in accordance with the FERC Uniform System of Accounts. SDG&E proposes using 1988 transfer rates, 14% for nonbenefits and 38% for employee pensions and benefits, to project 1991 to 1993 Account 922 amounts. The resulting electric department credit is estimated to total $ 14,158,000 in 1993. DRA agrees with the use of this methodology, and that agreement is reflected in the settlement as well. However, the final number is related to amounts otherwise adopted [*78] for Accounts 920, 921, and 926.

1.9.4 Account 923 Outside Services

The settlement proposes adoption of the uncontested forecast of $ 4,194,000 for expenses related to professional consultants and others (such as accountants, auditors, actuaries, and lawyers) for general services not specifically applicable to other accounts. The settlement adopts SDG&E's uncontested estimate of $ 4,194,000 for test year 1993.

1.9.5 Account 924 Property Insurance

This account includes amounts for the amortization of premiums for both general and nuclear insurance policies, such as for fire, storm, and explosions, and to cover losses of uninsured property. Without explanation, SDG&E offers its estimate of $ 4,296,000 for 1993. DRA based its estimate of $ 3,497,000 for this account on an eight-year average. DRA cites the cyclical nature of insurance premium expense as supporting an averaging approach.

The settlement adopts a budget of $ 3,797,000 be adopted for Account 924.

1.9.6 Account 925 Injuries and Damages

This account includes amounts reserved for uninsured losses and the amortized costs of insurance premiums for coverage of losses incurred through claims, and suits [*79] for injuries and damages to people and property. SDG&E testifies that the account was forecast using individual policy premium projections for comprehensive and public liability insurance and legal and settlement costs related to historical and known injury and damage claims. The resulting forecast is $ 8,590,000.

DRA agrees with SDG&E's estimates except with respect to directors' and officers' liability insurance coverage.

DRA argues that the Commission has in the past charged utilities with making an adequate showing as to how this insurance expense should be shared by ratepayers and shareholders, in accordance with the benefits that, historically, were received by each. SDG&E has made no such showing in this application. DRA suggests that:

"This particular expense must be shared, at least equally, between shareholders and ratepayers. DRA agrees that this coverage is necessary to attract well qualified individuals to serve, both on the board of directors and as corporate officers. However, ratepayers are not participants in the selection of these individuals and, therefore, can only benefit when a well managed company provides them top quality service at reasonable rates. [*80] It would be unfair to expect SDG&E's ratepayers to totally indemnify the company, removing the need for careful scrutiny and selectivity among the shareholders when choosing directors and officers . . ."

DRA's adjustment to this account results in an estimate of $ 7,518,000. This is a reduction of $ 1,071,700 for the electric department. Nonetheless, the settlement would have the Commission adopt a forecast equal to that originally proposed by SDG&E ($ 8,590,000). The settling parties argued that the Commission approved full recovery of directors and officers insurance in D.91-12-076 (SCE's general rate case decision) and that such recovery should be granted here.

The SCE general rate case decision issued last December did not address the question of shared responsibility for directors' and officers' insurance. Thus, that decision provides no guidance as how to resolve the issue as raised by DRA in this proceeding. SDG&E points out that DRA did not oppose full recovery of directors' and officers' insurance in the SCE general rate case. SDG&E argues that by not taking issue with DRA's failure to oppose these expenditures, the Commission was implicitly approving the full recovery [*81] of directors and officers insurance.

It would be most disturbing if the Commission were to approve a rate increase based simply on the fact that DRA has failed to oppose similar rate increases in past proceedings. The record in this docket raises a serious policy question which need not be resolved in order for us to approve the settlement. The parties should be aware that an open issue remains as to whether or not ratepayers should bear the full costs of insurance for directors and officers.

1.9.7 Account 926 Employee Pensions and Benefits

Account 926 includes premium expenses for health and welfare programs in excess of amounts paid by employees; the company's portion of funds provided for the SDG&E employee savings plan; amounts paid to fund the company's pension plan, the company's cost of life insurance and medical coverage for retired employees; and other employee benefit and welfare expenses.

SDG&E's benefits program consists of a pension plan, a savings plan, medical and dental coverage, life insurance, long-term disability protection, and certain mandatory benefits such as unemployment and disability insurance. The company reports that its total cost in 1990 [*82] for discretionary benefits was 9.7% of its straight-time payroll. This, SDG&E argues, was a lower percentage than that for any other electric and combined utility company in the state. According to SDG&E, it has held its costs below the average partially through a greater degree of cost sharing by employees and partially by holding the line and benefit enhancements. The company implemented a flexible benefits program in 1990, allowing it to gain a certain additional amount of cost control. Company-wide, SDG&E's forecast for employee pension and benefit expenses in 1993 is $ 42,404,000.

DRA recommended a $ 10,281,000 reduction to this request. This recommendation reflects the following conclusions and recommendations:

1. Limit Post-retirement Benefits Other Than Pensions (PBOPs) to a pay-as-you-go level.

2. Adopt DRA's revenue requirement because it reflects the most recent recorded premium, budget, claim, and expense data available. DRA's recommendations also incorporate the most recent changes in planned design, administration, and actuarial accounting. DRA argues that the use of more recent information and actual recorded data make its recommendation more accurate and [*83] reliable.

3. Adopt a medical expense inflation factor of 0.81% per year, which is derived by taking an average of expenses historically experienced by the company. DRA argues that this recommendation provides a greater incentive for SDG&E management to maintain health care cost increases at its current trend levels rather than focusing rate recovery on national trends that do not apply to SDG&E's situation.

The portion of SDG&E's requested expense level attributable to electric A&G expenses is $ 29,600,000. DRA's recommendation would result in an electric A&G expense of $ 20,995,000. For the purposes of the settlement, the parties propose a forecast expenditure of $ 24,444,000.

The settling parties report that this figure reflects the PBOP expense level being limited to the pay-as-you-go basis, however, it is not possible to determine how much of the reduction in revenue requirement results from the PBOP pay-as-you-go basis and how much results from the compromises apparently struck on the other issues.

1.9.8 Account 927 Franchise Requirements

This account reflects payments to municipal and other government authorities in compliance with franchise, ordinance or similar [*84] requirements. The settlement reflects the use of SDG&E's uncontested approach for calculating 1993 franchise requirements by using the otherwise adopted base rate revenues and appropriate franchise fee rates.

1.9.9 Account 928 Regulatory Commission Expense

This account includes expenses incurred in connection with formal cases, hearings, and investigations before regulatory commissions. SDG&E used 1988 recorded data, increased for additional anticipated regulatory requirements to derive its electric department forecast of $ 4,932,000. DRA proposed a forecast level of $ 4,444,000, reflecting a difference of $ 488,000.

For the purposes of the settlement, the parties agree on a forecast of $ 4,623,000. It is appropriate that SDG&E be allowed to recover the cost of intervenor fees through its fuel-related balancing accounts in a manner consistent with other major California energy utilities. The settlement reflects a reduction for this purpose.

1.9.10 Account 929 Duplicate Charges-Credits

In this account, SDG&E tracks the costs for its internal use of electricity. The parties agree, through the settlement, to adopt SDG&E's uncontested forecast of $ 1,412,000.

[*85]

1.9.11 Account 930 Miscellaneous General Expenses

This account includes research and development expenses; expenses related to securities, such as services for transfer agents, trustees, and stock exchange fees; industry association dues and memberships; general advertising; directors' fees and expenses; abandoned projects and software development for small projects.

In the decision approving a modified attrition adjustment for 1992 (D.91-10-046), the Commission approved a settlement endorsed by the same parties offering a settlement in this proceeding. In the modified attrition settlement, the parties agreed to a specific funding level for RD&D expenses in both 1992 and 1993. Consistent with this agreement, SDG&E requests $ 6,004,000 for RD&D expenditures in 1993. The company offered extensive explanations of its RD&D plans for 1993 and beyond, and these will be discussed below. However, the total forecast for electric department expenses in Account 930 is $ 11,025,000. SDG&E has not provided a detailed explanation of how it intends to spend the remaining $ 5,021,000 contained in its Account 930 forecast. Nonetheless, for the purposes of the settlement, the parties propose [*86] a 1993 forecast of $ 10,491,000. While none of the non-RD&D dollars in this account have been justified, certain specific expenditures were highlighted in DRA's report, and merit discussion here. Public relations and advertising expenses are tracked in Account 930.12. DRA points out that public relations expenses (including advertising) have been disallowed by the Commission for a number of years. DRA points out that D.84902 *(78 CPUC 638),* dated September 16, 1975, was one of the earliest and most detailed of a long list of decisions disallowing these expenses. As DRA states, "The Commission has repeatedly placed all utilities on notice that a substantial showing is required and must be part of the initial application, if this subject is to be considered. SDG&E has made no such showing as part of this general rate case." On this basis, DRA recommends disallowing $ 166,089 for the Electric Department.

For the purposes of this settlement, the company has agreed with DRA that ratepayers should not pay the cost of pension benefits provided to members of the Board of Directors. This is consistent with our conclusions in D.91-12-076 (the last SCE general rate case decision) wherein [*87] we stated, "Pensions for members of Edison's Board of Directors are not necessary and should not be recovered in rates."

According to DRA, SDG&E is requesting to recover abandonment cost of $ 495,335 for test year 1993, to be tracked in Account 930.216. The Electric Department's allocated amount for these costs is $ 369,520. As DRA explains, from time to time utilities stop work on minor capital projects that have not been completed. Such abandoned projects are not included in rate base (where the utility could earn a return on the investment) because these projects have never become "used and useful" to ratepayers. DRA explained its position concerning the inclusion of such amounts in rates as follows: "DRA is opposed to including these dollars in this account. DRA requested from SDG&E a specific list of abandoned projects that would meet the criteria set forth in Commission D.89-12-057. These criteria must be met before a utility can attempt to recover its cost for an abandoned project. However, SDG&E's response stated, 'It is SDG&E's position that the minor abandoned projects charged to A&G are not at an expense level high enough to justify being examined individually by [*88] the full criteria.' SDG&E then proceeded to discuss projects that had been abandoned in 1988. These, obviously, are not the 1993 abandoned projects that SDG&E is forecasting in this general rate case. Since SDG&E feels that the expense level is too low to justify specification, then it should follow that these expenses do not need to be included in rates. DRA recommends that because SDG&E has failed to meet its burden of proof in this matter that the entire amount of $ 369,520 be disallowed. In this regard, SDG&E's forecast is not only unsupported by the record, it appears to be inconsistent with existing Commission policy."

DRA also reports that SDG&E failed to provide any response to the staff's request for information concerning a forecasted level of $ 267,862 for SONGS-related abandoned projects. SDG&E also failed to provide the detail necessary to explain its request for "Contributions and Dues-Other Common" to be tracked in Subaccount 930.231, with an Electric Department allocation of $ 155,168. In these areas, SDG&E's failure to make an affirmative showing in this record is compounded by its apparent failure to provide adequate detail in response to DRA's data request. [*89]

In 1991, SDG&E chose to discontinue paying dues to the Electric Power Research Institute (EPRI). As part of its filing in last year's modified attrition proceeding, SDG&E indicated that it wished to reinstitute EPRI funding during 1992. In the settlement that was approved in D.91-10-046, the parties agreed to an EPRI funding level of $ 3,600,000 (in 1992 dollars), reflecting $ 3,500,000 in dues and $ 100,000 for participation in technology transfer. The modified attrition settling parties agreed that SDG&E must return to ratepayers any portions of that $ 3,600,000 amount not paid to EPRI during 1992. It was also agreed that the need to return such funds would be determined in this general rate case.

The parties to the settlement in this proceeding have made no reference to this refund provision. At the same time, SDG&E projects a 1992 EPRI dues level of $ 3,023,000, which is $ 577,000 less than was allocated for that purpose in the modified attrition decision last year. Since the end of 1992 is yet to arrive, it is too soon to determine whether or not the projected level of EPRI dues will be achieved. As part of this decision, we will direct SDG&E to report on its actual [*90] 1992 EPRI dues and to account for any allocated funds in its next attrition filing.

1.9.11.1 Research Development and Demonstration Fund

In the settlement among the parties to last year's modified attrition proceeding (as approved in D.91-10-046) the parties agreed that the total 1992 proposed revenues for RD&D should be $ 7.0 million (in 1992 dollars), exclusive of franchise fees and uncollectible expense. Of this amount, $ 3.5 million represents EPRI membership fees and $ 100,000 represents the cost for participation in technology transfer. What remains is a $ 3.4 million budget for specific RD&D programs. One condition of the settlement in the modified attrition proceeding is that SDG&E's RD&D programs and expenditures for test year 1993 would be the same as those in 1992 plus an inflation adjustment. For the purposes of its application in this proceeding, SDG&E states that it established a 1993 test year budget of $ 6,004,000 (1988 dollars) for RD&D activities "as agreed in the 1992 modified attrition settlement." The settlement agreement in this proceeding would have the Commission adopt this $ 6 million figure not only for 1993, but for the attrition years of 1994 [*91] and 1995 as well. The settlement agreement was silent as to the programs that would be funded through this budget.

In the Comparison Exhibit, in response to an inquiry from the ALJ, the parties at first indicated that they intended for SDG&E to continue with the programs approved in the modified attrition decision. Then, SDG&E reported that it was willing to accept a series of recommendations included in the report of Jolynne Flores on behalf of DRA. SDG&E presented a revised RD&D planning document as part of its showing in the update hearings. The revised plan includes program changes in response to DRA's concerns but proposes no change in the level of overall funding.

The California Energy Commission, which is not a party to the settlement agreement, proposes that the Commission approve a larger RD&D budget, directing SDG&E to augment its plan by including increased funding for an advanced gas turbine project and funding for participation in a multi-party solar thermal electric project. All of the settling parties opposed the Energy Commission's proposal.

The Energy Commission reported that, to stimulate the development of advanced aero-derivative gas turbine generators, [*92] a number of utilities headed by PG&E have formed the collaborative utility advanced gas turbine project. The project has three stages. In Phase 1, which is currently underway, proposals have been received for engineering and economic studies. The studies will be completed in late 1993. Phase 2 will involve the design and construction of a 50 to 200 megawatt demonstration project. Phase 3 will involve the construction and operation of a commercial plant. The target date for commercialization is 2000 but the program could be modified to accelerate development to accommodate the nearer term needs of the participants. The Energy Commission recommended that SDG&E contribute $ 250,000 in 1993 for Phase 1 of the project (and $ 500,000 annually in each of 1994 and 1995 for Phase 2). The Energy Commission argued that those amounts are the minimum necessary for SDG&E to participate on the steering committee for both phases of the project, to have a vote on important project decisions and to receive the full benefits of the project.

The Energy Commission also recommended SDG&E participation in the Solar 2 Demonstration Project. As the Energy Commission explains, first generation central [*93] receiver technology has been successfully demonstrated in the Solar 1 Project headed by SCE and the Los Angeles Department of Water and Power. Solar 1 used water as the heat transfer liquid. Research, development and testing have shown that a molten nitrate salt offers considerable advantages over water. SCE has organized a consortium of utilities and other interested parties to convert Solar 1 into a 10 MW demonstration project for the molten salt technology. According to the Energy Commission, the purpose of Solar 2 is to reduce the technical and economic risk of building commercial size (100 MW) central receiver plants. The Energy Commission estimates that the first 100 MW plant could be brought on line in 1999 or 2000.

The Energy Commission recommends that SDG&E provide $ 1 million for Solar 2 in three annual installments of $ 333,500 from 1993 through 1995. As with the advanced gas turbine project, the Energy Commission believes that this is the minimum level necessary for SDG&E to participate fully in project management so that it can help tailor the project to meet its needs and can receive important benefits, such as rights to the intellectual property produced by the [*94] project and any power generated.

SDG&E has declined to adopt the Energy Commission's recommendation and the other signatories to the settlement agreement have spoken in support of the company. SDG&E has now committed $ 100,000 from its 1993 RD&D allocation to support its involvement in the advanced gas turbine project, and indicates that this level of involvement will be sufficient to assure full participation including voting rights. Consistent with our policy of allowing each utility to maintain discretion over the exact expenditure of RD&D funds within the boundaries of certain guidelines, we will not direct the company to invest in the advanced gas turbine project at the levels originally proposed by the Energy Commission, nor will we insist that the company participate in Solar 2.

The projects presented by the Energy Commission appear fully worthy of participation, but so do the projects proposed by SDG&E. We will encourage the company to consider directing funds toward these projects, where appropriate, by granting it full discretion to redirect funds to either or both projects at the funding level proposed by the Energy Commission without seeking further Commission review. [*95]

We face broader concerns in considering the appropriateness of SDG&E's research and development plans for the test year and the two years which follow it. In D.91-12-076 (SCE's most recent general rate case), the Commission expressed its disappointment with the SCE's RD&D showing. Its case was affected by the lateness of its program changes and the insufficiency of its cost information. We are faced with similar concerns here, as SDG&E has proposed significant changes in its program as late as the update hearings in September, and provided virtually no information to justify the estimated costs of specific projects within each program area. We are inclined to approve SDG&E's program because of the company's efforts to meet at least some of DRA's concerns, specifically the appropriate funding level for projects related to natural gas vehicles and the need for increased supply-side research.

SDG&E's plan and proposed budget are conspicuous in their silence as much as by their descriptions. As discussed earlier, SDG&E does not report on the level of dues payments that are made to EPRI. As required in the settlement approved in last year's modified attrition proceeding, SDG&E [*96] must return to ratepayers any sums received through revenues to cover EPRI payments that did not occur. In addition to requiring SDG&E to make such a showing in conjunction with its next attrition proceeding, we will continue this requirement for any subsequent years where the company elects not to make full dues payments to EPRI. The settlement in the modified attrition proceeding for 1992 also included a requirement that SDG&E make provisions during this general rate case to return RD&D royalties and licensing to ratepayers. The settlement is also silent on this issue. We will require SDG&E to make a full report and propose appropriate refunds as part of its next attrition filing.

DRA's RD&D report in this proceeding included a series of recommendations and conditions affecting RD&D programs. In the comparison exhibit, the settling parties indicated that SDG&E accepted DRA's recommendations and conditions and was preparing a revised planning document for RD&D to address those issues. The revised plan was placed into evidence during the update hearings. However, the revised plan fails to sufficiently address a number of recommendations contained in the DRA report, and fails [*97] to provide program funding information on an annual basis. DRA recommended that SDG&E: (1) increase its level of end-use research (not by increasing the overall budget but rather by redirecting established budget funds), (2) create a separate end-use research program, (3) account for energy efficiency research as part of DSM program costs, (4) increase utility research coordination, and (5) better quantify ratepayer benefits from research projects. As part of its filing for next year's attrition proceeding, the company will be required to file a report identifying the steps it has taken to implement each of these portions of the agreement. We expect the company will work with DRA and the other regulated energy utilities in proposing a means for increasing the coordination among the utilities undertaking research and development efforts. In addition, the company should include, in its report, RD&D funding levels by program area on an annual basis.

The settlement is also silent on the issue of the appropriate RD&D funding range to be adopted in this proceeding for use in the next GRC. The funding range requirement was set for in D.90-09-045 and states that if the utility's rate [*98] request for RD&D spending is within a previously approved funding range, the utility could focus its initial showing on an explanation of its broad policy directions. In D.91-12-076 (the Edison rate case), the Commission called for the setting of funding range criteria in R.87-10-013 (the RD&D rulemaking). Since new rules have yet be issued, we must determine the appropriate range in this proceeding.

The company reports that from 1989 through 1991, its research funding, excluding the nondiscretionary tariff to the Gas Research Institute, ranged from 0.31 to 0.33% of the company's annual gross operating revenues. During this period, the company reports that it found the level of 0.30% of annual gross operating revenues to be the lowest level of funding to allow for the conduct of meaningful research. This funding level, according to SDG&E, does not allow for a fully balanced program in end use, supply distribution, and transmission areas. The company maintains that it needs funding in the range of 0.30 to 0.45% in order to implement a meaningful RD&D plan. At this range, SDG&E would project a minimum and maximum RD&D budget of $ 5,019,000 to $ 7,528,000 (assuming total annual [*99] billed revenues for gas and electric sales for test year 1993 of $ 1,672,897,000). The company maintains, and DRA agrees, that this range will allow for the budget to reflect flexibility suggested in D.90-09-045 and would also allow for changes in the operating environment.

We find this approach for establishing a range of RD&D expenditures to be reasonable for use in the next general rate case. In that we anticipate issuing rules to consistently affect all energy utilities RD&D planning efforts, we emphasize that our approval of the described approach in this proceeding does not indicate a determination that this is the appropriate policy to apply in other instances.

A few final words on the subject of RD&D report details are in order. While it is critical that the company's RD&D report include sufficient background information to place each program and project component in context, it is also important that the report contain enough information to allow the Commission to understand that the funding level for a given project is reasonable. The Commission does not intend to make judgments about how each RD&D dollar should be spent. Nonetheless, enough specific budget information [*100] must be included to provide the Commission with confidence that the funding decisions being made by the company are reasonable. We will expect SDG&E to provide a more detailed showing in subsequent RD&D reports.

1.9.12 Account 931 Rents

This account includes rental payments for office space for general office personnel and for communication lines, telephone, radio, and microwave equipment. The settlement endorses the uncontested forecast of $ 2,263,000 for this account.

1.9.13 Account 935 Maintenance of General Plant

This account includes the costs of maintaining the general office building, transportation, stores, and miscellaneous structures of the company. This includes the office furniture and equipment used in the general office as well as communication equipment. In the proposed settlement, the parties agree to adopt the uncontested company forecast of $ 2,383,000. SDG&E states that it employed a five-year historical average to forecast maintenance and plant costs, but neither specifies the five years used for the historical average nor justifies the reasonableness of their use. The proposed forecast level represents a 50% increase over maintenance costs [*101] in 1989, the last year for which recorded information is available.

1.9.14 Taxes

The methodology to be used for calculating taxes in this proceeding is not controversial. In that appropriate calculation of taxes is dependent on forecasts adopted in other accounts, the accuracy of those calculations is subject to the same issues raised in discussion related to other accounts.

1.10 Depreciation

SDG&E and DRA have agreed upon a methodology for calculating depreciation that is reasonable for the purposes of this settlement. It relies heavily on mechanisms put in place during the last general rate case for SDG&E and approved in D.88-12-

085. The appropriate level of depreciation depends on the weighted average plant which is adopted.

1.11 Amortization

1.11.1 Land Rights

The settling parties agreed to adopt the uncontested forecast of $ 1,372,000 for the costs related to rights in land. This amount appears reasonable for the purposes of this settlement.

1.11.2 Abandoned Projects

SDG&E originally sought a five-year amortization of preliminary engineering and licensing service costs for three projects that it has now abandoned: The South Bay Unit [*102] 3 Clean Air Project, the Combined Cycle Project, and the California-Oregon Transmission Project (COTP). DRA originally opposed the amortization of costs related to the South Bay Unit 3 and the Combined Cycle Projects. In the settlement, parties have agreed to allow SDG&E to amortize all of the costs for each of these three facilities, although the period for amortization is extended to six years and does not allow for the recovery of carrying costs related to these amounts. The result is a revenue requirement increase of $ 1,505,000 per year for a six-year period.

DRA appropriately summarizes Commission policy related to instances where we allow the amortization of abandoned plant (as stated in D.89-12-057): (1) that the project ran its course during the period of unusual and protracted uncertainty, (2) that the project was reasonable throughout its duration in light of both the relevant uncertainties that then existed and of the alternatives for meeting the service needs of customers, (3) when the project was canceled, and (4) that it was canceled promptly when conditions warranted.

It is important to note that the treatment for these costs proposed in the settlement can only [*103] be found reasonable here because it is encompassed in a much broader settlement. SDG&E has presented evidence which, if fully litigated, would have provided the company with at least colorable arguments for some recovery through amortization. DRA has also presented a substantial showing that would argue against recovery for the Combined Cycle and South Bay Projects. Thus, in a more limited settlement, it would be reasonable to include some level of recovery to reflect the relative litigation risks inherent when there are arguments to be made by both sides. However, the settlement offered in this instance allows for full recovery. The only exception is that carrying costs are not allowed. The Commission generally does not allow recovery of carrying costs for plant that is not used and useful. The amortization plan proposed here can be accepted solely because it is part of a broader settlement, representing various trade-offs among the parties.

1.11.3 Software

SDG&E originally requested that $ 2,850,800 in costs related to new software projects be included in rates in each of the next five years to amortize the costs for those new products. SDG&E has not named or described [*104] the software products nor explained why their use is necessary or reasonable. DRA had recommended the disallowance of costs related to six individual software projects resulting in a test year reduction of $ 518,200.

For the purposes of the settlement, a test year budget of $ 2,475,000 is adopted.

1.12 Amortization Reserve

The figure adopted for this purpose is dependent on the resolution of issues concerning land rights and software as well as the use of recorded 1991 data which was not available when SDG&E filed its testimony.

1.13 Rate Base

1.13.1 Plant-in-Service

The settlement reflects a compromise between DRA and the company on the value of rate base additions for 1992 and the test year. SDG&E originally estimated its 1992 electric plant additions to total $ 221,262,000 while DRA estimated additions totaling $ 175,646,000, reflecting a difference of $ 45,616,000. These parties also disagreed on the appropriate forecast for plant additions in 1993, with SDG&E forecasting $ 316,088,000 and DRA predicting $ 222,959,000, a difference of $ 93,129,000.

One of the challenges presented by this settlement is that the Settlement and Comparison Exhibit are silent [*105] as to the plant addition figures that are being proposed for either 1992 or 1993. By examining the workpapers underlying the settlement, we would find that it reflects a reduction of SDG&E's 1992 beginning-of-year plant-in-service balance by $ 33,000,000, a reduction of 1992 plant additions equaling $ 25,000,000, and a difference in 1993 weighted average plant additions of $ 32,000,000. However, these figures are not in the record and thus cannot be relied upon in making this decision. All that is apparent in the record is that the settling parties have agreed to not include some of the company's estimated plant-in-service cost in the rate base calculations for this proceeding. Normally, a general rate case would provide an opportunity to reflect on the company's recorded plant-in-service and determine which projects, if any, should not be allowed to remain in rate base. If adoption of the settlement implies that some of the company's estimated beginning-of-year 1992 plant-in-service should be disallowed, what cost should we expect the company to remove from rate base? If adoption of the settlement would result in disallowance of millions of dollars worth of plant additions [*106] that the company had intended to place in rate base, what assumption should the company make as to which projects have been disallowed?

One example may help to illustrate this concern. In its report on the results of operation for SDG&E's electric department, DRA objected to what appeared to be a $ 2.2 million 1992 plant addition which reflects environmental cleanup costs associated with the Esco substation. DRA's concern is understandable, in light of the Commission's policy to allow utilities dollar-for-dollar recovery for reasonable hazardous waste cleanup costs (to encourage responsible utility conduct)[20] but to proceed with great caution before including such expenses in rate base[21] (under the theory that utilities should not be allowed to profit from environmental damage they may have a hand in causing). As is true with all other proposed plant additions, the settlement is silent as to the proposed treatment of the Esco cleanup costs. In the update hearings in this proceeding, however, it came to light that SDG&E understands its agreement with DRA to imply that the Esco cleanup costs can go into rate base. SDG&E argues that such treatment is appropriate because the [*107] cleanup activities relate to substation conversion work that is currently in progress. Despite this argument, the record does not support an assertion that the cleanup activities are either a prerequisite to an upgrade of the substation or in any way related. Even if it could be established

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[20] See, however, D.92-11-030 which solicited comments on whether reasonableness review is the appropriate procedure for recovery of hazardous waste expenses. In that decision (at p.8 of the slip opinion), the Commission stated, "[b]ecause the complexities associated with Hazwaste cleanup activities may make it very difficult to establish, so many years after the fact, that all expenses were prudently or imprudently incurred, the reasonableness review procedure may not be the best vehicle for determining rate recovery for Hazwaste cleanup expenses." At the same time, the Commission authorized, in the interim, the continued use of the advice letter/memorandum account procedure for tracking of hazardous waste cleanup expenses.

[21] See, for instance D.88-07-059, 28 CPUC 2d 550, and D.88-09-020, 2 CPUC 2d 185.

that the cleanup activities were related or necessary for the improvement of the substation, the Commission has not established that these criteria alone should result in allowing such costs to be capitalized.

[*108]

This example draws us to conclusions that are both specific and general. Specifically, we wish to make it clear to SDG&E that in the absence of prior Commission approval, the company should not place hazardous waste cleanup costs related to Esco or any other project into rate base. We do not approve the inclusion of the Esco cleanup costs that have been brought to our attention in rate base. Generally, this problem underscores the need for more specific information about the ways in which this settlement affects the disposition of specific projects.

1.13.2 Plant Held For Future Use

SDG&E has proposed placing property valued at $ 255,000 in rate base as plant held for future use. DRA opposes this treatment and for the purposes of the settlement, the parties have agreed to exclude these costs from rate base.

The section of the settlement discussing this issue also includes agreement by the settling parties to adoption of plant held for future use guidelines set forth in Appendix B to D.87-12-066 (SCE's 1988 general rate case decision) with some modifications. In that there is no pending request to place any new plant held for future use into rate base, there is no need [*109] for the Commission to reconsider its 1988 guidelines at this time. We reserve reconsideration of our policy in this area to such a time as we are provided with a full range of arguments for and against such changes, in the appropriate proceeding.

1.13.3 Advances for Construction

SDG&E's test year 1993 estimate of $ 25,078,000 is based on recorded level of customer advances at the end of the year 1990, increased by forecasted collections and decreased by forecasted refunds. SDG&E estimated the collections as a function of electric customer gains using an ordinary least squares regression, while refunds were calculated based on 1990 refund data. DRA's test year 1993 estimate of $ 28,549,000 is based on the actual end of year 1991 level of customer advances, adjusted by SDG&E's forecasted net change to advances in 1992 and 1993. For the purposes of the settlement, the parties agreed to adopt DRA's estimate. This is reasonable in that the DRA's estimate relies on more recent recorded information.

1.13.4 Working Capital

Working capital consists of Fuel-In-Storage, Materials and Supplies, and Working Cash. There is no Fuel-In-Storage in rate base for the test year. [*110] SDG&E's estimate of $ 42,507,000 for Materials and Supplies was developed by taking the August 1991 recorded level of $ 41,654,169 and adjusting it to reflect expected increases in the cost of general supplies. The company's working cash estimate of $ 7,916,000 reflects an agreement between the company and DRA for the Electric Department, as stated in the Joint Petition for Modification of D.91-05-028.

DRA disagrees only with the calculation of Materials and Supplies. The staff calculated the ratio between the company's original estimate for Materials and Supplies and its original estimated weighted average plant in service. Applying the same percentage to DRA's estimated weighted average plant-in-service, the staff developed its test year Materials and Supplies estimate of $ 41,162,000. For the purposes of the settlement agreement, the parties propose using SDG&E's estimate of Materials and Supplies.

2. Natural Gas

For the purposes of many accounts, revenue requirements issues concerning natural gas parallel those related to electricity. In this discussion, we will focus on areas where there are distinctions.

2.1 Gas Sales and Customer Forecasts

The economic [*111] models used to determine the level of gas sales and customers are the same as those used for electric sales and customers. DRA was able to use more current information for its forecast and the models yielded a slightly lower forecast of sales and customers. The settling parties have recommended adopting DRA's estimate.

2.2 Gas Revenues

The settlement adopts DRA's estimate of gas revenues at present rates. DRA's estimate is derived by using billing determinants which come from DRA's customer and sales forecasts, which have also been adopted.

2.3 Miscellaneous Gas Revenues

In the settlement, the parties propose adopting a test year figure of $ 2,804,000, which is just $ 12,000 less than the revenue level proposed by DRA. This proposal closely parallels DRA's recommendation which relies on more current historical data and includes a forecast for gains from the disposition of gas plant (a factor that was not addressed by SDG&E).

2.4 Gas Supply Expenses

As SDG&E explains, gas supply expenses relate to purchased gas calculations, supply acquisitions including transportation and gas availability and price forecasting. These expenses include labor and materials [*112] for those activities. The settlement adopts SDG&E's forecast of $ 1,301,000 for these expenses. The entire forecast gas supply expense, however, is only $ 321,000, reflecting two specific credits. Supply expenses are credited to reflect the cost of gas used for compressor station fuel. This amount is offset by an equal debit in Account 854. In addition, a credit is applied for the cost of gas used for water and space heating at company facilities. This amount is offset by an equivalent debit reflected in various other accounts. DRA calculated its forecast using more recent recorded data and produced nearly identical results.

2.5 Gas Storage Expenses

As SDG&E explains, gas storage expenses are incurred for supervision and engineering, and operations and maintenance labor and expenses. The company's gas storage facilities currently include a buried pipe gas holder in an area referred to as Encanto and a remote liquified natural gas (LNG) facility at Borrego Springs. The Chula Vista LNG plant was decommissioned in 1985. No expenses for that facility are included in the test year 1993 estimate.

2.5.1 Account 840 Operations Service Supervision and Engineering [*113]

Almost all of the difference between SDG&E's forecast of $ 193,300 and DRA's forecast of $ 86,000 relates to hazardous waste cleanup assessment studies that need to be performed at three Towngas sites and at the decommissioned old Chula Vista LNG site. Prior to the development of pipeline systems to bring gas into San Diego County, facilities, commonly referred to as Towngas sites, were used to produce gas from coal and oil for local use. The process of manufacturing gas from coal and oil resulted in by-products that were disposed of on site. At the Chula Vista LNG site, although the plant's process equipment and storage tanks were removed from the site in the summer of 1990, hazardous waste cleanup activities may be required.

The settlement adopts a compromise forecast of $ 143,000.

2.5.2 Account 841 Operation Labor and Expenses

The settlement adopts SDG&E's proposed forecast of $ 56,000.

2.5.3 Account 843 Maintenance

This account includes the cost of labor and expenses incurred in the general supervision and performance of maintenance of high pressure storage holders and liquified natural gas holders. For the purposes of the settlement, the parties appropriately [*114] adopt a $ 30,000 forecast which is consistent with the forecast developed independently by SDG&E and DRA.

2.6 Gas Transmission Expense

These expenses are incurred for supervision and engineering; system control and load dispatching; communications system; compressor stations; gas, other fuel, and power used in compressor stations; and for the operation and maintenance of mains, measuring and regulating stations and other related transmission equipment. SDG&E's gas transmission system supplies gas to the various gas distribution systems within the company's service territory. The transmission system consists primarily of three large diameter pipelines and several crossties, two compressor stations and three major pressure regulating stations.

For the purposes of the settlement, parties propose adopting a forecast level of $ 5,044,000. The forecasts prepared by DRA and SDG&E in this area are consistent.

2.7 Gas Distribution Expense

These expenses are incurred for supervision and engineering; load dispatching; operation and maintenance of mains and services; measuring and regulating stations; meters and house regulators and for various customer service activities. [*115] Customer service activities include service turn-ons and shut-offs, seasonal relights and various customer service orders.

The parties propose, for the purposes of the settlement, the adoption of a forecast of $ 17,487,000 for these purposes. This is $ 115,000 less than originally requested by SDG&E and $ 75,000 more than originally proposed by DRA. Consistently, DRA's multi-year averaging technique produced estimates that were sufficiently close to those produced by the company to lend support to the initial request.

2.8 Customer Accounting and Collections

The numbers used here are derived from the analysis related to electric department customer accounting and collections discussed above in Section 1.7.

2.9 Gas Marketing Expense

The discussion of electric marketing expense included, above, as Section 1.8, applies fully to the gas marketing expense account, with one exception. The $ 635,000 in Account 912 applies to SDG&E's natural gas vehicle (NGV) marketing program rather than the electric vehicle marketing program mentioned in the electric marketing expense discussion. As with the electric vehicle marketing program, the settling parties have agreed that the [*116] cost of SDG&E's NGV marketing program should be deferred to the low emission vehicles investigation, I.91-10-029.

2.10 Administrative and General

The forecasts set forth in this section are derived from the analysis for electric department A&G expenses, discussed herein in Section 1.9.

2.11 Gas Department Depreciation

There is no difference between the settling parties on either the methodology or rates used to depreciate plant in service. Differences in depreciation expense forecast are solely and directly the result of differences in weighted average plant assumptions. SDG&E has utilized new mortality and forecast life studies as well as new salvage percent studies.

2.12 Gas Department Amortization

The analyses of DRA and SDG&E produced virtually identical results for the forecasted expenses related to land rights amortization. The settlement resolves minor differences between DRA and SDG&E concerning the appropriate expense for the amortization of software by adopting DRA's lower numbers. SDG&E had sought recovery of $ 1,975,000 ($ 395,000 per year over a five-year period) related to abandonment of the South Bay LNG removal project and the Borrego LNG [*117] special study project. For the purposes of the settlement, the parties agreed that these abandoned gas projects would not be reflected in the revenue requirement for this proceeding, nor would SDG&E seek to recover these costs in any future proceeding.

2.13 Gas Rate Base

2.13.1 Plant-in-Service

In the comparison exhibit, SDG&E reports that it used end-of-year 1990 plant data for beginning-of-year 1991 and estimated additions thereafter. SDG&E's estimate of 1993 beginning of year plant was $ 667,659,000. However, SDG&E's tables for plant-in-service have a conspicuous gap between 1988 and 1991. Thus, the record does not contain the end-of-year 1990 data that the company claims it relied on. DRA used end-of-1991 data to produce its 1992 beginning-of-year balance in plant-in-service to produce corroboration for $ 656,447,000 of SDG&E's estimate for 1993.

The comparison exhibit indicates that for the purposes of the settlement, the parties agreed to adopt $ 663,182,000 as the beginning-of-year 1993 estimate for plant-in-service. According to the settling parties, more recent information was available to them at the time of the settlement and the settlement reflects [*118] that data. However, any more recent information that may have been available to the parties has not been provided to the record in this proceeding.

Similarly, SDG&E's estimate of weighted gas plant additions for 1993 amounting to $ 23,007,000 is not cited in the record, nor does SDG&E itemize the costs related to the components of its plant additions estimate. As we stated for electric plant-in-service, as part of its next attrition filing, we will require that the utility include a report, signed by a representative of each settling party, that identifies and quantifies each project disallowed from beginning-of-year 1992 plant-in-service, from 1992 plant additions, and from forecasted 1993 plant additions, in a manner consistent with the rate base amounts included in the settlement agreement. This report will be subject to review and approval or rejection by the Commission as part of the attrition process.

2.13.2 Customer Advance for Construction

DRA and SDG&E utilize the same methodology for developing forecasts for customer advances and have produced virtually identical results. For the purposes of the settlement, the parties adopted SDG&E's estimate, which further [*119] reduces rate base.

2.13.3 Working Capital

In a manner consistent with the determination of working capital for the electric department, DRA and SDG&E have proposed the adoption of the uncontested amount of $ 3,365,000 for test year 1993. This suggestion is consistent with the Commission's actions in D.91-07-014.

3. Steam

3.1 Steam Sales and Customer Forecast

SDG&E's steam heat system produces steam for the space heating and cooling as well as the water heating requirements of a limited number of customers in downtown San Diego. Until late 1989, boilers located at the company's Station B were operated to produce the steam which was subsequently expanded through the house turbine to reduce the pressure of the steam for delivery to the customers. During 1989, two package boilers were installed at Station B to produce the steam and to allow the less efficient boilers to be shut down. With the installation of the package boilers, the house turbine is not required to reduce the steam pressure and its operation has been discontinued.

SDG&E is in the process of making a transition out of the business of providing steam heat. This is consistent with the Commission's [*120] directive in D.85-12-108, dated December 20, 1985. In that year, SDG&E had 51 steam customers. By 1988, the company had reduced that number to 31. In the test year, SDG&E anticipates having only six customers remaining. The company has established its sales forecast by conducting a survey of its steam customers. These forecasts have been incorporated in the settlement.

3.2 Steam Production Expenses

In D.85-12-108, the Commission also determined that SDG&E should recover full costs of the Station B steam production from the steam customers. The company initially forecasted its steam production expenses to total $ 606,000. DRA forecasted 1993 test year steam production expenses to total $ 552,000, reflecting a $ 54,000 difference. For the purposes of the settlement, the parties propose adopting $ 595,000 as the test year revenue requirement, capturing virtually all of the amount proposed initially by SDG&E. We will examine the differences between the parties on an account-by-account basis.

3.2.1 Account 602 Steam Heat Expense

SDG&E utilizes a 1984 to 1988 average of recorded expenses, reduced by an amount equal to the costs associated with the operation of the [*121] house turbine, in arriving at its test year forecast of $ 363,100. The use of pre-1989 data for the purposes of this forecast is puzzling in light of the fact that the company has dramatically changed its steam production techniques since 1989. As DRA points out in its testimony, there is no apparent reason to avoid using post-1988 data to forecast steam expenses, since there was no apparent direct relationship between the SCE merger activities and the operation of the steam production department. Using 1989 and 1990 data, DRA produced a steam heat expense forecast of $ 307,000.

3.2.1 Account 612 Maintenance of Steam Heat Equipment

Using the same pre-1989 approach, SDG&E forecasts its maintenance expenses to be $ 243,200 during the test year. Using the 1989 and 1990 data, DRA produced virtually identical results.

3.3 Steam Distribution Expenses

SDG&E initially forecasted $ 67,000 in distribution expenses for the test year 1993. DRA's forecast supports $ 63,000 of this expense. The settlement proposes the adoption of DRA's $ 63,000 estimate.

3.4 Customer Accounting and Collections

The numbers in the settlement for these accounts are consistent with those [*122] derived in the analysis related to the electric department included above in Section 1.7.

3.5 Administrative and General

Similarly, A&G expense forecasts are derived in a manner consistent with those discussed in Section 1.9 above.

3.6 Depreciation

There is no difference between the settling parties on either the methodology or the rates used to depreciate plant in service. Differences in the depreciation expense forecast in the parties' initial showings were solely and directly the result of differences in weighted average plant.

3.7 Plant-in-Service/Plant Additions

DRA's estimate for plant-in-service is virtually identical to that prepared by SDG&E, even though the company did not have the benefit of end of the year recorded information for its forecast. The settlement proposes adoption of $ 6,137,000 for test year 1993 plant-in-service, an amount that is within $ 3,000 of the estimates of either party.

DRA and SDG&E agree on an estimate of $ 15,000 for materials and supplies and a working cash amount of $ 79,000 for test year 1993.

4. Additional Issues Related to the Settlement

4.1 Productivity

As time goes by and technologies improve, it [*123] is expected that utilities will deliver utility services more efficiently. In D.85-12-108, *20 CPUC2d 115, 200* (the

Test Year 1986 GRC), the Commission expressed concern that SDG&E's "relative performance in various categories of productivity seem(ed) suboptimal in comparison with other California utilities." For this reason, the Commission said, "(W)e will expect SDG&E to develop productivity measurement tools and standards in the future and to provide a showing on productivity in the next rate case." Subsequently, in D.86-12-095, *20 CPUC2d 149, 178* (Pacific Gas and Electric Company's 1986 Test Year GRC), the Commission adjusted PG&E's revenue requirement to reflect productivity gains and stated that it expected all of the utilities to seriously address productivity issues in future general rate case proceedings. In response to this mandate, SDG&E produced a productivity study for this proceeding, the results of which appear to be supported by DRA's productivity analysis.

Productivity measurement as it has been performed by SDG&E and DRA, involves the development of a ratio of outputs (kilowatt hours and therms) to inputs (ratepayer dollars). The expectation is that improvement [*124] in this ratio should result in savings to ratepayers. SDG&E's analysis, in this case, involved examining recorded and projected costs for all years starting with the 1988 base year and ending with the forecast revenue requirement for 1993, and comparing those costs with the number of kilowatt hours of electricity sold or expected to be sold during the same period. Based on this analysis, the company concluded that the revenue requirement requested in the current application reflects compounded productivity gains of 8.2% since 1988. The parties to the Settlement then argue that since the Settlement would result in the company receiving even less revenue than it originally requested, its adoption would ensure that the company will achieve even greater productivity gains.

Developing assurance that SDG&E's revenue requirement reflects the appropriate level of productivity gains is of particularly great significance in this proceeding. First, the company wishes to base over 40 percent of its forecasted expense on costs recorded in 1988. Since the Test Year is 1993, these numbers are five years out of date. This fact, alone, provides exceptional potential for failing to capture efficiency [*125] gains. Second, this utility may be almost uniquely in a position to have accomplished substantial new efficiencies in the last five years. As time goes by, less of the company's electric generation plant is in rate base, since the company has not recently built new power plants and is substantially dependent on out-of-service-area power purchases. In addition, the company was forced to undergo the rigors of cost-cutting efforts during the pendency of the SCE merger. SDG&E has 200 fewer employees today than it did just prior to the merger process.

Nonetheless, the productivity analysis offered by the company and affirmed by DRA provides no basis for us to determine if the company has appropriately captured, in its base rate revenue requirement, the efficiencies gained during the last five years. Neither does it allow us to determine that the company has improved its operations and cut its costs as it should have in response to its unique situation.

One problem is that the company's analysis does not merely involve O&M and other costs that are the subject of this proceeding. It looks at all of the company's costs, including fuel costs that are reviewed in ECAC and BCAP proceedings. [*126] Thus, to offer one hypothetical example, the company's fuel cost assumptions for the Test Year could have been optimistically low, creating an over-all impression that the 1993 revenue requirement reflects productivity gains. These apparent gains might disappear during 1993, without any change in base rates, if fuel costs turn out to be higher than predicted. Further, the company's Test Year O&M forecast could reflect great inefficiencies and we would never be able to tell, since the productivity impacts of those expenses are not separated, in SDG&E's analysis, from the impacts of favorable power purchase contracts, or stable or declining fuel costs.

Another problem is that an excessively high Test Year forecast could overshadow and defeat the benefits of earlier productivity gains. To offer another hypothetical situation, SDG&E may have achieved productivity gains substantially greater than 8.2% in earlier years, only to have those gains partially offset by substantial rate increases in the last modified attrition and current Test Year. New positions or added costs included in the revenue requirement might actually introduce significant inefficiencies into the company's operations. [*127] If this occurred, it would evade the analysis of the productivity experts testifying in this proceeding. The company may not have achieved, or may simply have failed to capture in its revenue requirement, productivity gains in the cost areas that are the subject of this proceeding. There is no way for us to know, based on the record before us.

The Settlement Agreement is largely silent on the issue of productivity. Yet, productivity is a critical issue because of its magnitude. For instance, if the appropriate level of productivity gains is over 8%, then the potential electric rate impact is over $ 57 million (compared to the $ 72 million electric rate increase proposed in the Settlement). One way to determine if gains achieved in O&M and other related accounts have resulted in reductions to the revenue requirement is to identify specific efficiency-related reductions associated with various programs. However, the company has only been able to identify about $ 2 million in reductions it expressly made from 1988 expenses to reflect productivity gains. In the context of an electric revenue requirement in excess of $ 700 million, this is less than four tenths of one percent. [*128] The company argues that it has implicitly captured additional savings, but has provided no calculations to support this claim.

In addition, there is no way to tell, based on this record, that the company should not have achieved even greater efficiencies as a result of its unique situation. In other words, it argues that it has incorporated an 8.2% reduction, but provides no evidence to demonstrate that 8.2% is enough. As cited above, productivity was first raised as an issue for this company when the Commission was concerned that SDG&E was not performing as efficiently as it should. Yet, the record does not enable us to place the 8.2% estimate in context.

To support its argument that it has gained great efficiencies, the company boasts of its favorable employee-to-customer ratio and its in-house programs to encourage cost reduction. These are factors that should help keep the base rate revenue requirement low. We just cannot tell, based on the record before us, that the potential benefits stemming from these factors are reflected in the revenue forecast.

An additional concern is that the company's productivity analysis is limited to a study of the Electric Department. [*129] SDG&E should also be measurably improving the efficiency of its operations in the Gas Department. It is less likely, although not impossible, that the company could achieve productivity gains in its increasingly limited steam operation.

We will require that future productivity studies include an analysis that isolates the cost components that are subject to review in a General Rate Case proceeding. The utility should also report on recent productivity gains experienced by other energy utilities and other comparable industries. In addition, the utility will be required to demonstrate how the productivity gains reflected in the study have been applied to reduce the forecast revenue requirement.

4.2 Gain Sharing and The 10% Solution

Two components of the company's effort to reduce costs are the Gain Sharing program and the 10% Solution.

Gain Sharing awards are paid to employees when actual O&M or capital expenditures are less than originally budgeted for a given purpose, or when customer satisfaction goals are exceeded. To pay for the awards, the company uses about half of the O&M savings resulting from the awarded performance. The remainder of the savings are retained [*130] by shareholders. In 1988 alone, this program resulted in rewards to employees exceeding $ 4 million.

The 10% Solution is an employee suggestion plan in which employees are rewarded by receiving 10% of the first year's annual cost savings stemming from improvements that are implemented as a result of their suggestions. The remaining 90% of the savings are retained by shareholders.

The current issue raised by consideration of these admirable programs, is how rates should be adjusted in the next test year following any resulting improvements to reflect the fact that ratepayers can now be served at a lower cost.

These programs offer a significant incentive for employees and shareholders to encourage ongoing efforts to cut costs. For instance, SDG&E reports that the employee suggestion program has generated nearly $ 12 million of first-year annual cost savings. Employees were awarded approximately $ 1.2 million and, in the first-year savings alone, the shareholders received an extra $ 10.8 million. But the incentive payments to shareholders do not stop there. Suppose, for example, that $ 1 million of savings were generated in 1989. After payments to the innovative employee or [*131] employees in question, the shareholders would retain $ 900,000. Because the suggestion would continue to generate savings, the shareholders would also receive an incentive reward of $ 1 million in 1990, $ 1 million in 1991 and $ 1 million in 1992, for a total reward of $ 3.9 million.

Is a $ 3.9 million incentive payment for a $ 1 million improvement enough to encourage the company to seek cost-cutting changes in the future? Without conducting behavioral research, we would hazard a guess that, in most instances, it is. Nonetheless, the settlement includes a proposal that SDG&E be allowed to continue to receive, for at least another three years, a portion of the revenues needed to cover these expenses that no longer exist. When the company has made reward payments to employees, it has booked those payments as if they were O&M expenses and continued to book them in each subsequent year (even though the payments were only made once). Under the settlement, the revenue requirement for at least the next three years would continue to provide the company with extra revenues equal to half of these one-time incentive payments.

We want to encourage the utility to be creative in its efforts [*132] to reduce the cost of service. However, we want to be assured that, after the company is amply rewarded for those efforts, the savings are fully passed through to ratepayers by adopting a forecast that reflects no more than the costs actually expected to be incurred. One of the major reasons for adhering to a three-year rate case cycle is to encourage each utility to streamline its operations where appropriate, with the promise of being able to retain any resulting savings that accumulate before the next general rate case comes along. However, it is appropriate that revenues be reduced, in the subsequent rate case, to reflect the actual cost of service. We do not agree with the assumption that the company should continue to earn on its past cost-cutting efforts even in the years following the next general rate case and adopt no such policy in this decision.

III. Non-Settlement Issues:

A. Demand-Side Management

The settling parties chose not to resolve DSM issues in the Settlement Agreement. Instead, after SDG&E and DRA separately submitted DSM testimony, SDG&E, DRA and UCAN submitted a Joint Recommendation Concerning DSM Issues (Joint Recommendation).

1. Joint Recommendation [*133]

1.1 Programs and Funding

The parties recommended a 1993 test year total DSM funding level of $ 58.2 million (in 1993 dollars). Initially, SDG&E had requested $ 64.5 million and DRA had proposed $ 62.4 million. This figure does not include amortized portions of the 1990 and 1991 DSM rewards. It does include the cost of the Residential Appliance Efficiency Incentives Program, which SDG&E proposed to be bid to third parties in the DSM rulemaking proceeding (R.91-08-003). This program is discussed further, below.

The following table (as reproduced from Attachment B of Exhibit 6) summarizes the programs, measures and funding levels proposed in the Joint Recommendation.

TABLE 2-A

(FOR JOINT TESTIMONY)

SUMMARY OF SDG&E'S 1993 GENERAL RATE CASE PROGRAMS BY MEASURE

$ 58,232,537 TOTAL BUDGET IN 1993 DOLLARS

[SEE ILLUSTRATION IN ORIGINAL]

The description of the recommended programs and measures will not be repeated herein. It is found in the company's Revised Report on Demand-Side Management (Exhibit 4) and is modified in the Joint Recommendation in the following ways:

1. Residential Information: The $ 500,000 recommended for the Cross-Cultural and Other Advertising component [*134] of this program includes $ 50,000 for research related to the advertising effort.

2. Residential Load Management: The recommended funding for Peakshift of $ 300,000 is to cover costs of terminating the program in 1993 assuming approval of termination by the California Energy Commission. For 1994 and 1995, these funds would be used for a demonstration photovoltaic program to be developed and initi-

ated in 1993 under the Residential Appliance Efficiency Incentives Program should photovoltaic technology prove to be cost-effective based on engineering analyses. Prior to committing to the program in 1993, SDG&E would file an Advice Letter including documentation and cost-effectiveness anaylses. If photovoltaic applications are not cost-effective, SDG&E would review plans for the use of these funds in 1994 and 1995 with its DSM Advisory Committee.

3. Nonresidential Information: The parties agreed that $ 3 million would be approved for a proposed Energy Technology Center. SDG&E is investigating this project with its customers and others and plans to present its recommendations to the DSM Advisory Committee for majority approval (the details of this approval process to be developed [*135] by the Advisory Committee). SDG&E vowed that it would not move forward in the absence of majority concurrence from the Advisory Committee.

4. Nonresidential Energy Management Services: Audits would be conducted, with the auditors recommending the installation of appropriate energy-saving measures. Savings would be counted toward shareholder incentives only for measures the installation of which is verified during follow-up visits conducted within 18 months of the original audit.

1.2 Spending Flexibility and Caps

The parties recommend that the company be allowed a certain amount of flexibility in deciding how to spend its DSM budget. They propose that the programs be divided into eight separate categories. With one exception, the company would be free to shift funds between programs in the same category. The exception is the $ 3 million per year included in the proposed budget for the creation of an Energy Technology Center. Because the expenditure of funds for this purpose is so uncertain, the parties propose that dollars not spent for that purpose be returned to ratepayers. SDG&E would also be allowed to spend up to 130% of its approved budget for New Construction [*136] and Residential Appliance Efficiency Incentive programs. The following table summarizes the proposed fund-shifting boundaries and spending caps and is derived from Attachment C to Exhibit 6.

Spending Flexibility and Cap

	Carry-Over Carry-Forward	Between Programs Within Category	In/Out of Category	Spending Cap n1
Category 1				
Residential Appliance Eff. Incentives n2	Yes	Yes	NA	NA
Nonresidential EE Incentives	Yes	Yes	NA	NA

	Carry-Over Carry-Forward	Between Programs Within Category	In/Out of Category	Spending Cap n1
Nonresidential EM Services	Yes	Yes	NA	100%
Total Category 1	Yes	Yes	No n3	130% n4
Category 2				
Residential New Construction	Yes	Yes	NA	NA
Nonresidential New Construction	Yes	Yes	NA	NA
Total Category 2	Yes	Yes	No	130%
Category 3				
Residential A/C Cycling	Yes	Yes	NA	NA
Residential Time-Of-Use	Yes	Yes	NA	NA
Residential Pool Pump	Yes	Yes	NA	NA
Interruptible/Curtailable	Yes	Yes	NA	NA
Total Category 3	Yes	Yes	No	100%
Category 4				
Gas A/C	Yes	Yes	NA	NA
Fuel Substitution Standard Incentives	Yes	Yes	NA	NA
Total Category 4	Yes	Yes	No	100%
Category 5				
Direct Assistance	Yes	Yes	No	100%
Category 6				
Residential Information	Yes	Yes	NA	NA
Nonresidential Information	Yes	Yes	NA	NA
Residential EM Services	Yes	Yes	No	100%
Category 7				
Measurement & Evaluation	Yes	Yes	No	100%
Category 8				
Other DSM	Yes	Yes	No	100%

[*137]

n1 The spending cap applies to the total for all programs within a category and not to individual programs. Additional funding up to the cap can be used for programs within a category at SDG&E's discretion.

n2 Portions of this program awarded to bidders will be removed from this category.

n3 Funding for Thermal Energy Storage and Fuel Substitution Custom Incentives is included in authorized funding for Nonresidential EE Incentives. While the funding comes from Nonresidential EE Incentives, expenditures and savings for projects will be reported under Load Management and Fuel Substitution.

n4 Nonresidential EM Services is excluded for purposes of the spending cap for this category.

Because of the uncertainty as to whether and when the Energy Technology Center will be created, we will disallow the current funding request. If the utility firms up plans and a budget for this facility, it may file an advice letter requesting memorandum account treatment. With this exception, we will approve the proposal for spending flexibility and caps. By designing a system of eight program categories, and by limiting fund shifting to changes within a given category, the system appears designed [*138] to maintain the overall priorities suggested by the spending plan before us. The 130% spending caps for the measures in categories 1 and 2 is appropriate to allow for aggressive implementation of these highly cost-effective measures.

1.3 Mid-course Corrections

When SDG&E wants to make changes to its program that are inconsistent with Commission authorization, it consults its DSM Advisory Committee. If there are no objections among the Advisory Committee members to the proposed changes, the company files an Advice Letter for Commission approval indicating that there are no objections. If there are objections, the company says so in its Advice Letter filing and anticipates that hearings will be necessary. The DSM Advisory Committee consists of representatives from DRA, CACD, the CEC, UCAN, the Natural Resources Defense Council, the California Department of General Services, the City of San Diego, the County of San Diego, the Sierra Club and the California State Department of Economic Development.

SDG&E and UCAN recommend that, in the future, Advice Letters be deemed approved 40 days after being filed if there are no filed protests and CACD determines that the proposed program [*139] changes are consistent with what has been reviewed by the Advisory Committee. DRA has not expressed support for this recommendation. The assumption in support of this proposal is that, since CACD is a member of the Advisory Committee and reviews proposed changes before an Advice Letter is filed, there should be no need for further extensive review of the Advice Letter.

Pursuant to the Commission's General Order 96-A, the Commission cannot normally approve an advice letter of this type until at least 40 days after the utility files it. Where a timely protest is not filed, CACD attempts to prepare its analysis and the appropriate resolution for the Commission's consideration as soon after the initial 40-day period as possible. This procedure not only provides for adequate notice and opportunity to protest, it also assures that CACD will have the time it needs to adequately study and consider the proposed changes.

It is not clear that, simply because CACD attends Advisory Committee meetings, it will have sufficient information and time before an advice letter is filed to fully review proposed changes. We see no need to undercut CACD's opportunity for full review. As we have said [*140] in the past, the advisory committees do not supersede the Commission's role in approving and overseeing programs. We need to assure that CACD has sufficient time to present to us all relevant arguments to be considered in reviewing an advice letter. In addition, we are concerned that applying a "deemed approved" approach might encourage CACD to recommend that advice letters be rejected in some instances, largely because CACD does not have sufficient time to complete its review. For these reasons, we will not adopt the SDG&E/UCAN proposal. At the same time, we encourage SDG&E to do everything it can to facilitate timely review of its advice letters by communicating early and often with CACD concerning the company's request and CACD's information needs.

1.4 Shareholder Incentives

The parties recommended that we adopt a variety of formulas to calculate shareholder incentive rewards, depending on the type of DSM program involved. These formulas would be used through 1995, unless a new shareholder incentive mechanism is adopted in the DSM rulemaking/investigation (DSM OIR/OII) (I.91-08-002/R.91-08-003) at an early date.

1.4.1 S-Shaped Curve

The parties would use an [*141] S-shape curve to define the relationship of energy savings to shareholder earnings for SDG&E's Residential Appliance Efficiency Incentives and its Nonresidential Energy Efficiency Incentive Programs. Separate S-shaped curves would be established for each program. n22

n22 In D.92-09-080, we approved a pilot bidding program for the Residential Appliance Efficiency Incentives. In that decision, we allowed the company to earn shareholder incentives using the same mechanism applicable to other resource programs. The company was also directed to file a report describing how the minimum performance goals are reflected in the incentive mechanism for this program. Any required changes can be incorporated in our final Phase I decision in this docket.

The proposed S-shaped curve is a shared savings mechanism with a variable share (similar to that adopted in SCE's recent GRC). The percentage share varies within a given program depending on performance and among programs depending on each program's incentive basis. The incentive basis is defined to be energy and capacity savings benefits minus weighted costs equal to 25% of utility incentive payments plus 50% of net participant costs [*142] plus 100% of utility administrative costs (all benefits and costs are on a present value basis).

Within a given program, the shareholders' earnings would vary as a function of the ratio between the achieved and forecasted incentive basis. If SDG&E delivered between 0 and 50% of forecast savings, it would incur a penalty which decreases at a constant rate reaching zero at 50% of forecast benefits. At this point, neither a penalty nor an incentive would be earned. From 50% to 75%, SDG&E would receive an incentive at the same constant rate that was used to calculate the penalty. Between 75% and 100% of forecasted benefits, the incentive rate would increase, reaching its maximum at 100%. Between 100% and 130% the incentive rate decreases. At 130% and above, the incentive rate again becomes constant at the same level earned between 0% and 75%. This increasing-then-decreasing rate of incentive produces the "S" shaped curve.

An individual share percentage is calculated for each program covered by this incentive mechanism. The incentive rate is set so that if actual savings exactly equal forecast savings for a given program, the incentive will equal the rate of return times the [*143] cost of that program. As a result, among the two programs, the variable share depends on the relative incentive basis.

This incentive mechanism would not set an explicit maximum dollar amount of incentive that SDG&E can earn for each program. As long as SDG&E improves upon its forecast incentive basis, the company would be able to increase the amount of incentives it earns. The mechanism does, however, limit the rate of incentive accrual once achieved savings exceed 130% of targeted savings. Above this point, additional savings would only earn additional incentives at the minimum rate established for each program.

1.4.2 Residential and Nonresidential New Construction Variable Shared Savings/Performance Adder Treatment

According to the parties, this mechanism is designed to promote the installation of measures that exceed applicable building standards and (in the instance of some specific measures) to promote the achievement of positive net present value Total Resource Cost (TRC) values and cost-minimization. An earnings cap of $ 2 million per year would be applied for the total of the New Construction Programs.

1. Nonresidential Prescriptive and Lighting Measures: [*144]

a. For any measure that is 10-15% more efficient than the applicable Title 24 Building Standards, SDG&E would receive an award equal to 6% of the net present value (NPV) of these measures calculated using the following formula:

Net Present Value = B - [UAC + (.5 x PC) + (.25 x UIC)]

Where: B = Avoided Energy and Capacity Benefits

UAC = Utility Administrative Costs

UIC = Utility Incentive Costs

PC = Net Participant Costs

(All calculations are on a net present value basis.)

b. For any measure that offers a 15% or greater improvement in efficiency as compared to Title 24 Standards, SDG&E would receive an award equal to 13.5% of the NPV of these measures calculated using the formula in a. above.

c. Performance Minimum And Penalty: The minimum performance level for these program elements would be 25% of the forecasted NPV calculated using the formula in a. above. If the minimum performance level was not achieved, a penalty would be assessed to SDG&E. The penalty would be equal to the amount of the calculated NPV below the minimum, multiplied by 13.5%.

2. Residential and all other Nonresidential Measures

The following incentive mechanism would apply for these programs: [*145]

a. For any residential measures that is 5-10% more efficient than the applicable Title 24 Standards, SDG&E would receive an incentive equal to 4% of the TRC present value of benefits only (not NPV) of the measure.

b. For residential and all other nonresidential measures that offer an improvement in efficiency of at least 10% as compared to the applicable Title 24 Standards, SDG&E would receive an incentive equal to 9% of the TRC present value of benefits only (not NPV) of the measure.

c. All other elements of the SDG&E proposal for these measures would be adopted. No minimums or penalties would apply to these measures.

1.4.3 Residential Energy Management Services and Direct Assistance Performance Adder Treatment

The following describes the utility incentive mechanism proposed for the Residential Energy Management Services and Direct Assistance Programs:

1. Reward Mechanism

SDG&E would receive a reward equal to 5 percent of all expenditures made by the utility on certain qualifying measures in the Direct Assistance Program and all expenditures in the Residential Energy Management Services Program.

2. Non-Qualifying "Big 6" Measures in the Direct Assistance [*146] Program

Measures which would not be eligible for determination of a reward to SDG&E:

a. Attic insulation,

b. Caulking,

c. Weatherstripping,

d. Low-flow showerhead,

e. Water heater blanket, and

f. Door and building envelope repairs which reduce air infiltration.

3. Direct Assistance Program Qualifying Measures

SDG&E reward-eligible qualifying measures and expenditures shall be all other improvements, devices, or appliances provided and or installed by SDG&E which improve energy efficiency including, but not limited to:

a. Compact fluorescent lights,

b. Furnace filters,

c. Duct wrap,

d. Appliance services, and

e. In-home education.

4. Minimum Requirements

The utility target for weatherized units in the Direct Assistance Program is 7,000 per year. SDG&E would not be eligible for a reward unless it weatherized a minimum number of units. The minimum would be 70% of the 7,000 unit target. A minimum of 15,000 services would need to be achieved in the Residential Energy Management Services Program before a reward could be earned for this program.

A unit would be considered weatherized if the need for all of the "Big 6" items was assessed for each [*147] unit and all of the needed items were installed in each unit under the SDG&E program. If a unit did not need any of the "Big 6," it would not be counted toward the minimum goal. Expenditures eligible for a reward would not need to be made in the same units as those counted toward the minimum requirement.

5. Reward-Eligible Expenditures for Direct Assistance

All expenditures directly attributable to the qualifying measure would be eligible for reward, in addition to 34 percent of all administrative or other program costs that are difficult to allocate between specific measures or jobs.

1.4.4 Discussion

The mechanisms proposed jointly by SDG&E, DRA and UCAN are similar to those adopted for SCE in its last general rate case, but portions have been adjusted to give SDG&E the potential of earning more for each increment of energy saved than SCE. The parties to the Joint Recommendation argue that it is appropriate for SDG&E to have the opportunity to earn more because it is regarded as offering better documentation of its programs and resulting savings. DRA makes the point in its testimony that the company has established a solid planning capability for linking program [*148] funding requests with longer-term resource planning activities. These conclusions support the parties' proposal which allows for moderately greater earnings potential, while adhering to the guidelines of D.92-02-075.

Our major concern in adopting incentive mechanisms at this time is that they be consistent with our interim policies adopted in D.92-02-075. We believe that the mechanisms proposed by the parties satisfy those policies, but a few observations are in order. First, the proposal is complex. Each type of incentive has its own specific rules and limitations. The danger is that a complex incentive strategy might influence company behavior in ways that are difficult to predict. It may not be possible to know, in advance, whether the potential for earning a five percent performance adder for one type of investment at the same time that the company could earn 13.5% of the net present value of savings resulting from another type of investment will motivate the company to make optimal investment decisions.

A second observation is that, while the record offers explanations for the relative differences among the types of incentives available for the company, we are not convinced [*149] an adequate showing has been made with regard to the overall level of incentives resulting from the proposal. While D.92-02-075 established interim guidelines and policies, the Commission said that the determination of appropriate level of incentives for SDG&E would occur in this general rate case. The Joint Recommendation reflects the maximum allowable incentive level within the current guidelines. We expected the parties to have analyzed the relative risks and associated returns commensurate with the proposed investment in DSM programs. The interim guidelines include a supply-side comparability feature, but we expect to fully explore the implications of this feature in the context of the rulemaking taking into account the experience with the joint proposal adopted in this proceeding.

We will approve the incentive arrangement proposed jointly by SDG&E, DRA and UCAN for other reasons entirely. We have committed ourselves to supporting a long-term effort by our regulated energy utilities to support DSM activities. CACD is currently studying the various incentive mechanisms that have been offered to the utilities in these initial years and we will focus our efforts in the DSM [*150] Rule-making docket on creating uniform guidelines for future incentive mechanisms and levels. DRA emphasizes that the incentive process as a whole remains, at this phase, an experiment and that the results of this experiment could ultimately lead to changes to the incentive approach or the elimination of incentives altogether. SDG&E understands that the incentives approved here may be temporary. We have not formed a commitment to continue the use of S-shaped curves or determined that current incentive levels are appropriate to the tasks at hand. Our continued commitment to supporting DSM activities will be demonstrated not by approving incentive levels that maximize earnings, but by establishing understandable, logical and predictable boundaries within which the utilities' programs can operate. For now, we will approve the incentive mechanism that the parties support in order to assure program continuity during these early phases of maturation. We also remind the company that further incentive guidance is on the horizon.

1.5 Accounting Transition Mechanism

SDG&E currently counts DSM achievements at the time a contract is signed with the customer, not at the time of equipment [*151] installation. The Commission has ordered in the DSM OIR/OII that the value of DSM savings be determined on an ex post basis beginning in 1994. SDG&E proposed a transition mechanism to change to counting DSM savings at the time of installation in 1993. Initially, DRA recommended that SDG&E change to counting savings at the time of equipment installation in 1993 without any transition mechanism.

The parties to the Joint Recommendation propose the adoption of a compromise Transition Mechanism to provide a complete transition to installed versus signed accounting by January, 1994. It has two parts:

1. If SDG&E exceeds its $ 9 million earnings cap in 1992, SDG&E would count savings from certain contracts (as described below) signed after the date the 1992 $ 9 million cap is exceeded, during the year in which the job was actually installed. Incentive payments made to customers for contracts signed after the cap is exceeded would be counted in the year the measures were installed; however, administrative

costs would continue to be charged to 1992 budgets for all of the 1992 contracts, whether the cap is exceeded or not.

Savings from projects would be counted in the following [*152] manner once the cap has been met. For contracts signed in December 1992, 80 percent of the savings would be counted in the year measures are installed. The percentage would be 60 percent for contracts signed in November and 40 percent for contracts signed in October 1992. No savings would be counted for contracts signed earlier than this even if the earnings cap has been met. For contracts signed in 1992 after the cap has been met where measures are installed in 1992, no utility earnings would be available.

The exact number of contracts needed to reach the $ 9 million cap for 1992 will be affected by the final tabulation of administrative and incentive costs, as well as Commission acceptance of SDG&E's 1992 efforts. If the Commission, after its review of SDG&E's 1992 performance, determines that the date at which the earnings cap was met (if at all) is different from the date originally designated by SDG&E, contracts deferred into future years would be added to 1992 results at their full value, up to the $ 9 million earnings cap. Adjustments to 1992 expenses would be handled through the DSM balancing accounts.

2. A "gradual" transition to installed versus signed accounting [*153] would be implemented for contracts signed in 1993 as follows:

DSM ACTION Trigger	%Counted	%Counted	%Counted	%Counted
Contract Signing	100%	75%	50%	25%
Installation	0%	25%	50%	75%

For example, if a contract was signed in the 2nd quarter of 1993, 75% of the value of that contract would be counted toward the 1993 achievements in 1993. If the measure(s) were installed, for example, in the 4th quarter of 1993, the remaining 25% of that value could also be counted in 1993. If, however, the measure were not installed until 1994 (or some future year) the remaining 25% could not be counted until that time.

Neither component of this proposal will be adopted. As this proposal would add complexity to the incentives, it decreases our confidence that the incentives are not inconsistent. The first component appears to be an effort to smooth the transition from a year with an earnings cap (1992) to one without a cap (1993). We presume that some parties were concerned that when SDG&E's projected earnings exceed the cap for 1992, the company would be motivated to stall on the completion of new contracts, in order to gain the full earnings benefits from those contracts [*154] in the following year. However, this is not an issue unique to this transitional year. Whenever the utility runs up against an earnings cap, it may have an incentive to hold off on new contracts until the next year. For example, if the company employed such a strategy at the end of 1991, such delayed contract signing would have contributed to meeting or exceeding the 1992 cap.

A transition of this type is likely to make only the most marginal of differences. For instance, since the percentage of earnings saved for a later time would increase as 1992 draws to a close, the utility would have an incentive to put off October contracts to November, November contracts to December, December contracts to 1993. Instead of trying to stay a small step ahead of the utility's motivation, we prefer to make a clean transition. The 1992 program will be completed under the same rules that the company expected when the year began.

The second component would establish for 1993 contracts what the parties describe as a gradual transition from rewards for signing contracts to rewards for achieving installations. The concern is that it can take as long as 1 1/2 to 2 years from the time the contract [*155] is signed to the time the installation will be completed. This component of the transition does not appear to be necessary. First, by allowing for 100% of the reward in the year of signing for those contracts signed in the first quarter of 1993, the utility would have an incentive to sign contracts as early in the year as possible. However, this is the same incentive the company would have without the transition. If the company wants to get as many installations as possible completed during 1993, it should try to get contracts signed as early in the year as possible.

In addition, although a major reason for this aspect of the transition is to help stabilize the reward payments to the company, it is not clear that the proposal would have that effect. The proposal would promote high DSM earnings in 1995 (because the 1993 earnings are calculated in 1994 and introduced into rates in 1995). However, 1994 rewards, which would be introduced into rates in 1996, would be calculated solely on an "installed" basis. Hopefully, the same number of installations will occur regardless of when the reward is calculated. The joint recommendation simply postpones the inevitable impact of the [*156] change from a "contract" basis to an "installed" basis while further complicating the process of calculating incentive rewards.

If there has to be a less than smooth transition (and we are not convinced there will be) then any aspect of the DSM earnings formula that could help hold rates down should take effect as soon as possible. The sizable rate increase resulting from this application comes on the heals of a large increase in the modified attrition. In the midst of the current recession and minimal inflation, we should make sure that the utility's DSM activities do not raise rates unnecessarily.

1.6 Recovery of Shareholder Incentives

One way to help assure that DSM earnings do not bounce precipitously is to continue to amortize earnings over a three-year period. This is our current practice for rewards stemming from the collaborative DSM process. However, SDG&E, DRA and UCAN propose, allowing the company to collect its full 1991 reward resulting from the 1988 GRC DSM programs through rates in one year. After 1991, there is no longer a distinction between collaborative and GRC rewards. We do not adopt this proposal, because we find that it is logical to amortize [*157] all reward payments in a consistent manner.

For future periods, the parties to the Joint Recommendation propose allowing for one-year recovery of each year's reward. We reject this proposal, because it might tend to encourage greater fluctuations in rates and earnings from year to year. Instead, we will amortize both components of the 1991 reward, as well as rewards for DSM activities in future years, over a three year period.

1.7 1990 AND 1991 DSM Rewards

In its Report on Demand-Side Management SDG&E included a request for recovery of DSM rewards earned in 1990 and 1991 as follows:

1. 1989 GRC Reward for 1991 Programs: $ 7.15 million is requested for SDG&E's 1991 program results under the penalty/reward mechanism authorized in Decision 88-09-063. This is the maximum amount allowed according to the Settlement Agreement in SDG&E's 1992 Modified Attrition Application, approved in Decision 91-10-046.

SDG&E has provided its 1991 program results and support in its Annual Summary of DSM Activities filed March 31, 1992. These results were reviewed by CACD which, in a report filed August 17, 1992, found that most of SDG&E's savings were reasonable and recommended a reward [*158] level of $ 7,558,200. Since this amount exceeds the cap, SDG&E would be eligible for the full $ 7.15 million reward.

For activities stemming from its 1989 GRC DSM program, SDG&E has been allowed to earn rewards for having signed contracts with various customers for the installation of energy-measures, even before the measures were installed. SDG&E must refund any reward payments received for contracts that are subsequently cancelled. This is discussed, below, in the section concerning CACD's recommendations.

2. 1991 Collaborative Reward: $ 1.6 million is requested for rate recovery in 1993 for SDG&E's 1991 program results under the collaborative shareholder incentive mechanism authorized in Decision 90-08-068. This is one-third of the maximum re-

ward of $ 5 million allowed for 1991, which SDG&E has earned. The remaining two-thirds would be recovered in equal parts in rates in 1994 and 1995.

SDG&E has provided its 1991 program results and support in its Annual Summary of DSM Activities filed March 31, 1992. These results were reviewed by DRA, which agreed with the company's conclusions. Review of this reward has been transferred to this GRC from SDG&E's ECAC Application [*159] 91-09-059 by Decision 92-04-061. One-third of any authorized reward should be included in SDG&E's January 1, 1993 rates.

3. 1990 Collaborative Reward: $ .7 million is requested for the second one-third of SDG&E's 1990 program results under the collaborative shareholder incentive. The 1990 reward of $ 2.1 million was approved in D.91-10-046 in SDG&E's 1992 Modified Attrition Application. Recovery of this $ .7 million has been transferred to this GRC from SDG&E's ECAC A.91-09-059 by D.92-04-061 for recovery in the January 1, 1993 rates adopted in this proceeding. The final one-third of this reward should be recovered in 1994.

The record supports including, in the revenue requirement, appropriate sums to allow for recovery of the reward amounts requested by the company. The related revenue requirement will be calculated to allow for three-year recovery of all earnings, as discussed above.

3. CACD's Recommendations

In its report concerning the 1991 operation of the GRC DSM program, CACD made many recommendations that may help improve the operation and flow of information related to future DSM activities. The company has agreed to adopt many of those recommendations. [*160] The resulting changes are summarized as follows:

1. SDG&E will inform customers when suggestions designed to decrease electrical consumption will result in increased natural gas consumption (or vice versa). To assure that this information is conveyed, it will be included on a checklist given to the customer.

2. The company will include in its file for each commercial/industrial audit a summary sheet describing the nature of business operations at the audit site.

3. In its commercial/industrial audit files, SDG&E will also include reference materials to support its estimate for the cost and energy efficiency gains resulting from improvements that were recommended.

4. For contracts relating to Commercial Cooling improvements, SDG&E will include the following limitations: a two year expiration date, with a one year extension option for retrofit installations and a four year limit for new construction projects. This issue becomes moot in 1994 when rewards become subject to "ex Post" measurement.

5. SDG&E stated that it would be possible to add to its Annual Summary a table clearly showing the impact of contract cancellations on the total savings resulting from each program. [*161] We will require that the company include such a table in its Annual Summary.

The CACD report, included as Exhibit 61 in this docket, provides a clear explanation of the importance of each of these changes. We will direct the company to incorporate them in its DSM program activities.

As part of its audit, CACD examined the debit that SDG&E proposed to apply to the 1991 GRC DSM reward for the cancellation of contracts that were signed in 1989. SDG&E subtracted the nominal reward amount from the 1991 pre-cap reward total. CACD recommended that the 1989 contract reward amount be escalated to 1991 dollars using the 1989 GRC's DSM escalation value before subtracting out the cancellations. DRA recommended that both the 1989 cancelled contract reward amount and the 1991 reward amount be escalated to 1993 dollars and the subtraction be made at that point. DRA suggested that the formula used to escalate balancing account amounts should be used for this purpose as well. UCAN argues that it is not enough to only adjust the rewards received for cancelled contracts by an inflation factor; the ratepayer's lost investment opportunity should also be reflected.

Let us try to look at this [*162] issue from another perspective. In 1991, SDG&E received a reward for energy savings related to its 1989 program efforts that, because of the contract cancellations, will not be realized. The company must refund this portion of the reward to its ratepayers. By applying this "refund" to its calculation of savings achieved in 1991 (a year in which its calculated reward exceeds its reward cap), the company makes an adjustment that, at least for now, is merely on paper. If more existing contracts are cancelled in later years, the adjusted reward might fall below the rewards cap and SDG&E would be obligated to make an actual refund.

However, there is no logical reason to apply a reduction related to the 1989 reward to SDG&E's 1991 reward calculation. The reward received by the company in 1989 was not affected by a cap. Thus, any way you look at it, the ratepayers paid real dollars to the company as a reward for contracts that will produce no savings. That money must be returned to ratepayers. We will adjust the revenue requirement in this proceeding to accomplish a refund of this reward.

A question remains as to how to quantify this refund. SDG&E received its reward for these [*163] cancelled 1989 contracts through rates in 1991. By paying this reward through rates in 1991, SDG&E's ratepayers lost the opportunity to invest these funds for their own use. The nominal 1991 dollars should be adjusted to reflect that lost investment opportunity. The reward related to the cancelled contracts should be adjusted to reflect the short term Treasury Bill interest rates, for the years 1991 and 1992, the years in which SDG&E actually held the nominal reward amount of $ 880,740.

4. Balancing Account Undercollections and Offset Rates

The Electric Efficiency Balancing Account (EEBA) and Gas Efficiency Balancing Account (GEBA), were originally authorized in the Collaborative decision (D.90-08-068) for the period of August 29, 1990 through December 31, 1991. The balancing accounts were established because the Collaborative decision authorized only expenditures, not funding, and the utilities needed a way to record the expenditures for reimbursement in the future. These accounts were implicitly reauthorized by the Modified Attrition decision (D.91-12-074) for the period January 1, 1992, to December 31, 1992.

The electric offset rate was originally authorized by the [*164] 1991 ECAC (D.91-04-063) to be in place from May 1, 1991, through April 30, 1992. It was then reauthorized in the 1991 Modified Attrition Filing (D.91-12-074) and the 1992 ECAC (D.92-04-061) to be in place from May 1, 1992, to April 30, 1993. The offset rate authorized by the 1991 ECAC was set at a level intended to capture DSM expenditures from August 1990 to December 1991, which were not included in the base rates. (The Modified Attrition decision, D.91-12-074, also authorized funds for DSM that were included in base rates.)

The gas offset rate was authorized in SDG&E's most recent BCAP decision (D.91-12-075) and the 1991 Modified Attrition decision. This rate was based on a forecast of expenditures for January 1,1991 through September 30, 1991, and actual expenditures made from August 1990, through December 1990. The offset rate was expected to collect $ 3.37 million from January 1992 through December 1992. In addition, in the last BCAP decision, we authorized the two-year base rate amortization of $ 1,013,500, the forecast expenditure from October 1991 through December 1991. Accordingly, SDG&E is also collecting $ 0.507 million in base rates in 1992 and 1993. The forecast [*165] gas DSM expenditure from August 1990 through December 1991 was $ 4.4 million. The intention is that the offset rate and the additional funds from base rates would balance the GEBA by December 1993, if revenues were collected as previously approved. As a result of this pattern of decisions, the offset rates and the balancing accounts have been running on different cycles since they were established. SDG&E has had a four-month lag in the collection of revenue for the EEBA in 1992,and more than a year lag in gas revenue collection as described above.

SDG&E has proposed to terminate its EEBA, GEBA and corresponding offset rates at the end of 1992. However, SDG&E claims that early termination of the offset rates will result in an undercollection of $ 10 million in electric and $ 6 million in gas revenues. Thus, to zero-out the balancing accounts, SDG&E also proposes that the estimated amount of undercollection be included in the 1993 revenue requirement by amortizing it over the first year of the rate cycle.

The forecasted undercollections are based on the shortage of revenues that will occur if the offset rates are terminated earlier than planned. The rates were previously set [*166] at a level that would have to remain in place through May 1, 1993 for electric, and through September 30, 1993 for gas, in order to match authorized and forecasted expenditures.

We will adopt SDG&E's proposal to eliminate the balancing accounts and the offset rates, thus simplifying the DSM rate-making process. In this rate case we will use SDG&E's estimates of the electric undercollections to adjust base rates and thereby zero-out the electric balancing account. SDG&E should amortize the undercollected amount over the three year rate case cycle. However, because the figures for both expenditures and revenue collection are presented here only as estimates, some accommodation must be made for actual under- or overcollection through December 31, 1992. We will direct SDG&E to file an advice letter to true up the final amount after the EEBA and offset rate have been terminated.

When SDG&E files the advice letter it should specify the exact amounts recorded in the balancing accounts starting at the time of the Collaborative decision through December 31, 1992, and the exact amount of revenue collected by the offset rate from May 1,1991, through December 31, 1992. The true-up amount [*167] should be included in the 1993 Attrition filing. SDG&E should update the amortized amount for the attrition year to reflect the true-up with interest from January 1, 1993 to the time the new rate is implemented. The utility should complete the accounting and file the advice letter by February 1, 1993, in order to allow time for a resolution to be incorporated into the attrition filing.

According to SDG&E's revised forecast, the gas offset rate is only expected to collect $ 2.8 million by December 1992, leaving SDG&E with a shortfall of approximately $ 0.6 million. The gas offset rate was not intended to capture DSM gas expenditures made in 1992 and only a portion of the $ 8,930,000 that was authorized in the Modified Attrition decision for 1992 gas DSM will be recorded in the balancing account. Since $ 4,876,000 is being recovered in base rates, we calculate that $ 4,054,000 should be recovered in the GEBA and would be undercollected in 1992. However, SDG&E is predicting that $ 6.08 million will accrue in the GEBA by December 31, 1992. Having no detailed information from the company, we assume the additional $ 2.03 million reflects the spending flexibility authorized by the [*168] Modified Attrition decision, which gave SDG&E a cushion of $ 5.6 million for certain programs.

In total, SDG&E projects an undercollection of $ 6.9 million in the GEBA as of December 31, 1992. The company's predicted 1992 accruals of $ 6.08 million, when added to the 1991 undercollection of $ 0.6 million come close to equalling the total predicted undercollection. However, since there has been no audit of SDG&E's gas DSM programs, we have no assurance that the company's figures are accurate or that it has used its available funds in a manner consistent with our previous orders. In fact, we cannot even be certain that the extra $ 2.03 million relates to the $ 5.6 million cushion.

We find it beneficial to zero-out and preclude further use of the GEBA, as well as the EEBA, but cannot allow the collection of an extra $ 2.03 million without an audit. In addition, there will be some true-up value for the estimated expenditures from January 1991 through December 1992. While we authorize the amortization of $ 6.9 million over the next three years, the portion of the revenues that would be collected in 1994 and 1995 is contingent on the results of an audit of the GEBA. DRA should verify [*169] the $ 4.05 million, the remaining $ 2.63 million and any true-up amount and propose an adjustment in the next attrition filing, following the audit.

Finally, DRA should verify that SDG&E has not exceeded its $ 50 million cap for 1992 DSM programs. Because all of the 1992 DSM expenditure figures in this rate case are estimates, the Commission is still awaiting verification that SDG&E is within its spending cap for 1992.

5. SDG&E Headquarters Building Facade Lighting

The City of San Diego chose one issue to vigorously litigate in this proceeding. With the support of UCAN and DRA, the City strongly objects to SDG&E's long-standing habit of illuminating the exterior of its corporate headquarters with flood-lights. Prior to the raising of this objection, the company used a bank of 88 1,000 watt flood lamps, mounted at approximately the third floor level and pointing up, to wash the four faces of the headquarters building in white light. The company uses additional lamps to create a yellow crown atop the structure. Since the City has raised this objection, the company has selectively turned off some of the lamps and redirected others, reportedly resulting in a reduction of [*170] the over-all lighting by over 20%. Nonetheless, there is no disagreement that the SDG&E headquarters stands as a bright beacon on the San Diego skyline.

The City argues that the utility's lighting policy is inconsistent with its energy efficiency message and programs, for which the ratepayers are spending over $ 60 million per year. As with one eye open the company spends over 10% of its DSM budget to sensitize and educate consumers about the importance of conserving energy, with the other eye, it appears to wink, suggesting that leaving the lights on after everyone leaves the room is just fine. While producing scant supporting evidence, the City and UCAN argue that many of the area's residents are deeply offended by the company's lighting display. The City asks the Commission to order the company to turn off what remains of the 88 floodlights.

SDG&E is equally vigorous in defense of its building lighting policy. The company offers evidence that at least some downtown landlords and business associations like to have the floodlights burning, out of a sense that they enhance the safety in the downtown area. SDG&E argues that when people see the lights shining on the building, [*171] they do not get the sense that SDG&E fails to care about energy conservation, or that it is talking out of both sides of its corporate mouth.

The City offered evidence of a different corporate perspective that may have prevailed during the 1970s. During each oil crisis, SDG&E voluntarily turned off the lights and boasted that this act communicated to the community the company's strong desire to encourage energy conservation without compromising safety in the downtown area. SDG&E argues that its change in attitude is consistent with the difference in philosophy between the energy conservation efforts of the 70s and the demand-side management efforts today. In the 70's, as the company sees it, we all were willing to "freeze in the dark" for the sake of national security. In the 90's, according to SDG&E, we seek not to discourage energy use, but to assure that it is used efficiently.

SDG&E says that its facade lighting promotes safety by casting a glow onto the surrounding sidewalks. However, some may disagree as to whether it is more efficient to bounce 88,000 watts of power off of the walls of a skyscraper to cast a street-level glow than to simply provide a handful of strategically [*172] located streetlights. The City should be most concerned about promoting downtown safety, and it appears profoundly disturbed by the current lighting system.

We are certainly not going to tell the company how to light its building. Only the dreaded word "micro-management" could adequately describe the nature of such an edict. Nor is the evidence presented by either side strong enough to support the contentions made. Instead, we will offer a few observations.

There can be little doubt that SDG&E, or any other company, lights its building in order to send a message. That message may be one of corporate identity, of public safety, or of a certain perceived aesthetic. It would not be surprising to find that the desire to express each of these notions enters into the decision. Yet, if this is true, can there be doubt that, at least to some people, a brightly lit yet largely vacant building also communicates some form of indifference to the effects of impulsive energy consumption? We wonder if a heavily floodlit corporate landmark interferes with an otherwise heavily promoted conservation message, which is also so clearly identified with the corporation. In the final instant, [*173] SDG&E has to make that judgment. It would seem most appropriate that the company would work hand-in-hand with the City in crafting a resolution of this issue. The City, of course, may have the power to enforce the solution it finds most appropriate through the passage of an ordinance.

No matter what the company eventually does with its facade lighting, we remain concerned that it be more successful in inspiring efficiency than it may be in inspiring cynicism. This Commission has never advocated "freezing in the dark". We have, instead, since the 70's, encouraged the utilities to look at efficiency improvements as a resource and to mine that resource, when it is a cost-effective choice, to help meet customer demand. Beyond the influence the company may wield as a symbol of responsible corporate behavior, it is also a consumer of electricity and natural gas. It appears that while SDG&E encourages its other commercial and industrial customers to undergo energy audits, it has not undertaken a similar analysis of its own corporate headquarters. We will direct the company to undertake a comprehensive energy audit of its corporate headquarters as soon as possible and to submit with [*174] its next attrition filing both the results of the audit and the company's detailed plan for implementing the audit's recommendations. In that the company and its ratepayers should benefit from the audit process itself, the company should not include the results of such an audit in its reward calculation.

6. Pilot Bidding Program

In D.92-09-080 in the DSM rulemaking proceeding, we adopted SDG&E's proposal to put out its residential appliance efficiency program for bid by third parties. Pursuant to Ordering Paragraph 9, SDG&E is authorized to recover in rates a total of $ 19,599,159 (1993$) for its residential appliance efficiency incentives program and associated measurement activities. Determination of revenue requirement and rate design for this funding were deferred to this proceeding. We will include the pilot bidding program costs of $ 6.8 million in the revenue requirement approved in this order. We will also approve $ 6.8 million for 1994 and $ 6.7 million for 1995.

B. Emerging Business Enterprises

This comprises the activities we once referred to as Women and Minority Business Enterprises. After the execution of the Settlement Agreement, the CACD issued [*175] a Report on SDG&E's program costs entitled "Audit Report on the Emerging Business Enterprises Program Costs of San Diego Gas & Electric Company for 1993 Test Year". DRA and SDG&E propose that the revenue increase of $ 274,900 (1988$) recommended in that report be added to the revenue requirement identified in the Settlement Agreement. The parties included this amount in the total proposed for Account 930 in the Comparison Exhibit.

C. Affiliate Issues

In its audit report, DRA proposed the following changes affecting the relationship between SDG&E and its affiliated businesses:

1. SDG&E should not share directors with affiliated companies.

2. SDG&E should bill its affiliates fully loaded costs plus 5% for services it provides.

3. SDG&E's affiliates' share of corporate costs should be removed from SDG&E's costs for ratemaking purposes. This would result in a reduction of 1993 costs of $ 303,000.

4. SDG&E should provide the Commission with the following reports:

a. The annual financial statements of each affiliate company, including the consolidating workpapers of Pacific Diversified Capital Company (PDCC);

b. An annual statement which details the nature of all inter-company [*176] transactions concerning SDG&E, with a description of the basis upon which costs were allocated and transfer prices were established;

c. An annual report which details SDG&E's and its subsidiaries' proportionate share of 1) total assets, 2) total revenues, 3) total expenses, and 4) total employees;

d. An annual statement of all tangible and intangible property sold/transferred or otherwise used between SDG&E and its affiliates;

e. An annual statement of all employees transferred between SDG&E and its affiliates;

f. Immediate notification of the creation, dissolution, disposition or acquisition of any affiliate of SDG[E] and

g. Immediate notification of the sale or transfer of any property which has a value of $ 100,000 or greater between SDG&E and any of its affiliates.

After the Settlement Agreement was submitted, DRA agreed to withdraw the first and third proposals and SDG&E agreed to endorse the second and the forth. Although DRA has withdrawn its proposals to require entirely separate boards of directors and to remove all affiliate-related costs from rates, we emphasize that the Commission has not passed judgment on the appropriateness of these proposals.

D. Nuclear [*177] Expenses

The Settlement Agreement proposes that $ 4,922,000 (1993$) should be added for each additional SONGS refueling expected in 1993 in addition to the one refueling already included for Unit 2. After adjustment to conform to D.92-08-042, the $ 4,922,000 refueling cost becomes $ 4,732,000 in 1993$ which de-escalates to $ 4,093,000 in 1988$.

In its 1993 Attrition Year advice letter filing, SCE requests recovery of costs for a total of two SONGS refueling outages in 1993 (for SONGS Unites 2 & 3). Based on this information, SDG&E requests increasing its nuclear refueling expense estimate by $ 4,093,000 to reflect one additional refueling during 1993.

A decision is still pending on SCE's advice letter filing. We will allow SDG&E the recovery it seeks for a second refueling outage while reminding the company that we do not intend to make the ratepayers pay twice for the same expense. If either or both of the expected refueling outages do not occur in 1993, we will presume that the funds allocated in 1993 for that purpose will be applied to each refueling outage when it does occur. SDG&E will not be awarded recovery a second time for outage costs that are covered in this opinion. [*178]

E. Post-Retirement Benefits Other Than Pensions

On October 5, 1992, ALJ Michael Galvin issued a proposed decision in I.90-07-037 as consolidated with A.88-12-005 and I.89-03-033 which, if adopted, would change the accounting method to be used for tracking costs related to non-pension retirement benefits. SDG&E has distributed a late exhibit reflecting appropriate changes in the event that the Commission approves an order in I.90-07-037. The revenue requirement tables attached to this order have been modified to include the revenues forecast as being needed to satisfy the Galvin proposed decision.

F. Low Income Rate Assistance (LIRA)

The Settlement Agreement does not include any administrative costs associated with this program. The Settling Parties propose that these costs should continue to be recorded in the LIRA balancing account and recovered through SDG&E's ECAC and BCAP proceedings.

G. Intervenor Fees

The Settling Parties propose that intervenor fee compensation awards be recorded in ECAC and BCAP balancing accounts and be recovered through those respective proceedings. This is a reasonable proposal.

H. Low Emission Vehicles (LEV)

Although the utility [*179] proposes that some costs related to natural gas vehicle development be included in its RD&D budget, the Settling Parties propose that the recovery of other costs related to natural gas and electric vehicle activities be deferred to the LEV investigation (I.91-10-029).

We are concerned over the funding gap which may exist should the natural gas vehicle development program, authorized in D.91-07-017, end prior the completion of I.91-10-029. Should such a contingency develop, we authorize continued funding at current annual levels pending our order in the LEV investigation. The utility is authorized to continue the memorandum account treatment as authorized in D.91-07-017 between the expiration date of the account and the decision in the LEV investigation.

I. Environmental Costs

The Settling Parties argue that various environmental-related expenditures SDG&E may undertake during the 1993 - 1995 rate case cycle are too uncertain to be estimated accurately at this time. Instead, they suggest that a mechanism be created to allow for eventual recovery of reasonably incurred costs. They propose that SDG&E be authorized to use the memorandum account procedures described below to [*180] recover all reasonably incurred costs, subject to subsequent reasonableness review.

a. Expenditures subject to memorandum account treatment. The memorandum accounts procedure would apply to the following two categories of expenditures:

* Hazardous Waste Cleanup Costs. Cleanup activities covered in this category would include former manufactured gas plant sites. This category would also include all hazardous waste clean-up costs pertaining to the ESCO substation construction site incurred after the date of execution of the Settlement Agreement. Recoverable

expenses would include investigation expenses related to the remediation at the site, as well as all expenditures associated with actual clean-up activity.

Recoverable expenses would not include the costs of preliminary investigations conducted to provide an initial assessment of the contamination at a site and the associated health risks. Revenues for preliminary investigations were included in the Settlement Agreement revenue requirement.

* Environmental Compliance Activities. Costs of environmental compliance activities not specifically included in the Settlement Agreement revenues would be tracked through this [*181] memorandum account process. These activities include:

1. SDG&E Project No. 91078: Encina and South Bay Secondary Containment Waste Water Treatment Facilities,

2. SDG&E Project No. 91079: Senate Bill 14-Hazardous Waste Source Reduction,

3. SDG&E Project No. 91081: Bay and Estuary Plan -- mitigation measures required in connection with NPDES permits,

4. SDG&E Project No. 91080: Plant modifications necessary to comply with proposed APCD Rule 69, and

5. Compliance activities in response to other subsequently adopted environmental regulations.

b. Description of memorandum account procedures. SDG&E would pursue recovery of the environmental expenditures subject to memorandum account treatment through the following procedures:

* Hazardous Waste Cleanup Costs - For each hazardous waste management project site, SDG&E would file an advice letter that complies with the informational requirements previously specified for such advice letters in Decision 88-09-020. Following Commission approval of the advice letter request, expenditures incurred on such projects would be recorded in SDG&E's hazardous waste management memorandum account authorized by Resolution No. 2987 (March [*182] 31, 1992). Costs recorded in this account would be recoverable in rates to the extent the Commission subsequently determines them to have been reasonably incurred.

* Environmental Compliance Activities (except Rule 69-related NOx modifications at SDG&E power plants) - In Decision 91-10-046, the Commission authorized SDG&E to establish an environmental compliance memorandum account and to record certain environmental compliance expenditures incurred in 1992, following the filing and approval of an advice letter. The Settling Parties propose that the previously-ordered advice letter process be retained through the 1993-1995 rate case cycle

and expanded to include all applicable environmental compliance expenditures incurred during that cycle, except Rule 69-related NOx modifications at SDG&E power plants. Expenses recorded in the environmental compliance memorandum account would be reviewed for reasonableness in a future SDG&E ECAC, or such other proceeding as the Commission might designate. Expenses found to be reasonable would be included in SDG&E's rates.

* Rule 69-related NOx modifications at SDG&E power plants - The Settling Parties argue that before the Commission [*183] might approve memorandum account treatment of costs related to Rule 69-related NOx modifications at SDG&E power plants, the Commission may want to undertake more substantial review. Accordingly, following the adoption of the final Rule 69 by the San Diego Air Pollution Control District ("APCD"), SDG&E would be allowed to request permission to open a memorandum account for each generating unit that requires retrofit. In its advice letter filing, SDG&E would provide:

1. The Rule 69 compliance schedule and a forecast of compliance costs, including operation and maintenance costs, and refurbishment costs.

2. An analysis of the long-term plan for each plant for which SDG&E seeks permission to obtain a memorandum account.

3. A comparison of the long-term costs of retrofitting and operating the plant to various alternatives to retrofits. The alternative analysis will consider retrofits, plant retirements, repowering, and emission credits, if any, as applied under Rule 69 to the SDG&E system. Anticipating that the APCD compliance schedule may require immediate action by SDG&E, DRA would review the Rule 69 advice letter and offer a recommendation to the Commission within 60 days [*184] of the Advice Letter filing. Upon issuance of a Commission resolution, SDG&E would be authorized to record its Rule 69-related NOx modification expenses in a memorandum account. A separate authorization and account would be used for each generating unit. The recorded memorandum account expenses would be reviewed for reasonableness in a separate SDG&E application or a future GRC. Expenses found to be reasonable would be included in SDG&E rates. SDG&E would include the cost of complying with Rule 69 in future BRPU filings.

There are logical reasons to continue the practice of allowing the utility to track hazardous waste clean-up costs through memorandum accounts, as described above. Remediation activities and costs are subject to change at each stage of the clean-up process. We want to encourage the utility to remain fully responsive to clean-up needs. At the same time, the utility must establish the reasonableness of any clean-up expenses it wishes to pass through to its customers by showing not only that it incurred reasonable costs in its clean-up efforts, but that it was reasonable in its activities that led to the original contamination. The memorandum account process [*185] maintains the flexibility needed to meet these purposes.

We are not willing, however, to allow the company to extend the advice letter process to cover other costs that it describes as being related to environmental compliance. Although the Settlement Agreement adopted in last year's modified attrition proceeding allowed SDG&E to track some such costs in a memorandum account during 1992, this is nonprecedential under our settlement rules. This treatment may have been appropriate for the purposes of a modified attrition process four years distant from the last GRC (although D.91-10-046, which adopts the settlement, is silent on this issue), but environmental mitigation and compliance costs most appropriately should be considered in a general rate case along with other O&M and capital costs. Such costs should be considered by the utility when it makes decisions concerning its resource plan and its over-all spending priorities during each rate case cycle. They should be included in the costs considered by the Commission when it reviews the utility's spending plans.

Because such environmental compliance costs should be reflected in the planning process and carefully controlled, [*186] they should be approved in advance. We expect the parties to include a forecast for environmental compliance activities in their reports for the next GRC. In addition, we will allow the utility to respond to unexpected mid-cycle compliance requirements by filing applications requesting approval of special cost treatment. The applications can be handled in a manner consistent with the procedures outlined above, including review by DRA within 60 days. However, we will also require that the utility explain why it is reasonable for it to have failed to account for the project in question during the last GRC process.

In the meantime, the record does not include adequate information to allow for approval of funds for environmental compliance activities during the prospective rate case cycle. We will direct the parties to address 1994-1995 environmental compliance funding requirements as part of the modified attrition process in 1993.

A final comment is in order concerning hazardous waste clean-up costs. We expect this company and all other utilities to take reasonable steps to minimize the generation of hazardous wastes through the use of efficient processes, reuse, recycling and [*187] appropriate chemical substitution. When reviewing the company's clean-up expenses, we will consider the reasonableness of historical waste minimization efforts. In order to help the company contain its future clean-up costs, we will require that it undertake a company-wide waste minimization audit, to be overseen by CACD. In a manner similar to our past management audits, we will direct the company to hire outside experts to review the utility's processes and propose wasteminimizing changes where appropriate. SDG&E may seek recovery of costs related to this audit through an advice letter filing and memorandum account, just as it may currently seek to track its hazardous waste clean-up costs. We will review the results of this audit in the company's next GRC, along with a report from SDG&E on its plans in response to the audit's recommendations.

J. UCAN's Eligibility Request

UCAN is a nonprofit consumer advocacy group that has represented residential and small business San Diego area ratepayers in proceedings before the Commission since the group's inception in 1983. UCAN seeks compensation for costs it incurred as an intervenor in this proceeding.

On September 8, 1992, [*188] UCAN filed its Request for Finding of Eligibility. No party has filed any response to UCAN's request.

Rule 76.54 requires a request for a finding of eligibility for compensation to include the following: a showing that the intervenor would experience significant financial hardship by participating in the proceeding, a statement of issues that the participant intends to raise in the proceeding, an estimate of compensation that will be sought and a budget for the participant's participation.

The significant financial hardship test is passed if the participant has already received such a finding from the Commission during the same calendar year. The Commission made such a finding in D.92-07-066, issued in July, 1992. Thus, significant financial hardship is established for the purposes of this proceeding.

UCAN had already completed its expected participation in Phase I of this proceeding and distributed its testimony for Phase II when it filed its request. Its specification of issues that it has addressed will serve as its "statement of issues that it intends to raise." It has included an estimate of $ 150,000 for its participation in both phases of this proceeding. We find that [*189] UCAN is eligible to claim intervenor compensation.

UCAN also asks for authority to request compensation for its Phase I participation independent of any request for Phase II participation. Because Phase I is largely focussed on settlement-related activities and because the phases are being heard by different ALJs, we will grant UCAN's request in this instance.

K. Rate of Return

In D.92-11-047, issued on November 23, 1992, the Commission approved a new, lower rate of return and return on common equity for SDG&E. This change reduces the projected revenue requirement by approximately $ 30 million and has been incorporated in the appendices attached to this decision.

L. Revenue Allocation and Rate Design

Issues related to final revenue allocation and rate design are being addressed in the second phase of this proceeding. For the purpose of interim rate design, we have used the marginal costs, revenue allocation and rate design method employed in SDG&E's most recent ECAC and BCAP. In its comments on the draft decision, the California Street Lighting Association objected to several aspects of the calculations performed by CACD and included as appendices to the proposed decision. [*190] Several changes have been made in the interim revenue allocation and rate design calculations in response to these comments.

M. Payroll Taxes

SDG&E reports that in November, 1992, the 1993 limits for FICA and Medicare were set by the federal government. The limit for FICA is $ 57,,600 as compared to the $ 60,300 level previously assumed for purposes of the Settlement Agreement. The Medicare limit was reduced to $ 135,000 from the $ 141,151 level assumed for purposes of the Settlement Agreement. The total revenue requirement impact of these changes is a reduction of $ 79,000, which is now included in our revenue requirement calculation.

IV. Conclusion:

We adopt the Settlement Agreement under the conditions set forth in the ordering paragraphs. With few exceptions, we adopt the Joint Recommendation of SDG&E, DRA and UCAN for the funding and operation of the company's demand-side management program in the years 1993 through 1995. SDG&E is also provided the maximum reward allowed for its demand-side activities in 1991 and required to return to ratepayers previously earned rewards for efficiency improvement contracts signed in 1989 that were later cancelled. The adopted [*191] Summary of Earnings and supporting tables are attached to this decision as Appendices B through M.

Findings of Fact

1. On May 8, 1992, after DRA had filed its testimony in response to SDG&E's application, a Settlement Agreement addressing most revenue requirement issues was filed with the Commission.

2. For test year 1993, the settlement results in an increase in electric base rate revenues of $ 71.996 million or 5.01%, an increase in gas base rate revenues of $ 17.512 million or 3.83%, and an increase in steam base rate revenues of $ 882,000 or 92.45%.

3. In D.91-07-014, the Commission determined that the sales forecast adopted in SDG&E's 1992 ECAC proceeding should also be used for the purposes of this proceeding.

4. The Commission adopted SDG&E's ECAC sales forecast in D.92-04-061.

5. SDG&E's test year 1993 electric sales estimates have already been adopted by D.92-04-061 in SDG&E's ECAC proceeding.

6. SDG&E's forecast for test year 1993 electric miscellaneous revenues is $ 14,526,000.

7. DRA's estimate for test year 1993 electric miscellaneous revenues is $ 15,651,000.

8. The level of test year 1993 electric miscellaneous revenues included in the settlement [*192] is $ 15,057,000.

9. Both DRA and SDG&E support the company's zero based estimate totaling $ 1,209,300 on non-ECAC residual oil fuel handling expenses.

10. The two methodologies used to predict boiler operation expenses produce very similar outcomes.

11. In order to ensure an adequate supply of cooling water to the South Bay and Encina Plant, SDG&E plans to dredge both the South Bay Power Plant channel and the Encina Lagoon in 1993.

12. The parties to the settlement have agreed that the Heber expense ($ 600,000) should be deducted from the estimate for Account 506.

13. The company and DRA agree on the adoption of SDG&E's zero-based estimate of $ 9,488,800 for rents related to electric steam production, reflecting the annual lease payment for Encina 5 as well as leases with the Unified Port District, State Land Commission, and other miscellaneous entities.

14. Parties have agreed to adopt SDG&E's uncontested estimate of $ 677,700 in Account 510 electric expenses based on an adjusted average of 1984 through 1988 recorded expenses.

15. Relying on a five-year average of recorded expenses beginning in 1984, SDG&E estimated its structural maintenance expenses in the test year [*193] to be $ 4,574,700, while DRA's estimate, based on 1988 recorded expenses, is $ 4,755,800.

16. The agreed upon expense level for boiler maintenance in this settlement of $ 2,225,000 lies between the estimates of DRA and SDG&E and reflects the fact that either forecast methodology would produce reliable results.

17. The settlement's estimate of boiler overhaul expenses reflects the imputed savings due to "forced outage cost charged to capital instead of O & M".

18. The expense level agreed upon in the settlement for turbine maintenance is $ 1,099,000, reflecting a number lying between the results of two otherwise valid models.

19. The settlement adopts SDG&E's original turbine overhaul estimate of $ 2,814,900.

20. The settlement adopts DRA's 3-year amortization of the South Bay dredging expenses and otherwise relies on the 5-year average methodology employed by SDG&E resulting in an adopted miscellaneous electric maintenance expense level of $ 930,000.

21. In 1988 dollars, SDG&E's estimate for total nuclear power production expenses during test year 1993 is $ 66,855,800, based on a methodology and data presented in SCE's 1993 general case, A.90-12-018.

22. Since Unit 2 [*194] is scheduled for refueling in the third quarter of 1993 and Unit 3 is scheduled for refueling outage in the fourth quarter of 1993, a schedule change could cause all or portions of the refueling outage expenses to be incurred in a different calendar year than originally planned.

23. SDG&E has a nuclear department consisting of a manager, two senior engineers, two engineers, and a secretary.

24. According to SDG&E, the company's nuclear department personnel actively participate in the various SONGS working groups and provide information to the company's senior management so that they are well equipped to respond to SONGS-related issues.

25. DRA estimates SDG&E's test year nuclear expenses to be $ 57,795,000.

26. In the settlement, the parties agreed to adopt DRA's expense estimate, after making a $ 79,000 adjustment to reflect errors related to NRC fees.

27. From the outset, SDG&E and DRA have agreed that an expense estimate for gas turbine power and other power supplies of $ 2,393,200 is reasonable for the test year.

28. Both SDG&E and DRA derive the estimates for Account 560 by adjusting 1988 recorded costs to reflect a pattern of lower expenditures for information services, [*195] building services, and a lower level of labor, and agree on the resulting expense forecast of $ 885,300.

29. SDG&E and DRA use adjusted 1988 recorded cost to derive test year estimate of $ 1,334,000 for load dispatching costs.

30. SDG&E's estimate for this account is based on 1988 recorded data and includes an increase of $ 81,200 for landscaping expenses at the Penasquitos substation.

31. After a tour of the Penasquitos site, DRA staff concluded that the added expenses were not required because from all appearances, the landscaping is complete.

32. DRA argues that ratepayers should not be responsible to pay expenses related to additional water use after five years of drought in California, and that it is SDG&E's responsibility to install drought resistant, low maintenance landscaping.

33. The settling parties argue that it is reasonable to adopt SDG&E's original figure of $ 397,200 for Account 562 since SDG&E's conditional use permit for the Penasquitos substation requires the company to provide the disputed landscaping.

34. SDG&E and DRA agree that the cost of labor, materials, and expenses incurred in the operation of overhead transmission lines is estimated to be $ [*196] 513,600.

35. It is likely that SDG&E's transmission engineers will soon be facing additional responsibilities.

36. According to SDG&E, the Distribution Planning and Scheduling System provides a common information base to be used by management planners, designers, and construction personnel.

37. DPSS is a totally integrated management system that supports work order development, construction, maintenance, and project accounting for electric and gas distribution activities.

38. The Distribution Facilities Information System is another data base system designed to provide timely, accurate information concerning the company's distribution system.

39. DFIS produces electric maps from the data base as well as performing engineering and property accounting functions.

40. Although the company has provided a description of its goals in implementing the DPSS enhancements, it has not sufficiently addressed the legitimate concerns raised by DRA.

41. SDG&E and DRA agree that expenses during the test year for distribution load dispatching purposes should be forecast to be $ 856,100.

42. SDG&E's estimate of $ 2,522,500 for distribution station expenses is derived from the 1988 base [*197] of $ 1,846,300 and three adjustments totaling $ 676,200: increased hazardous waste handling costs, additional landscape maintenance cost of substation facilities, and a change in accounting related to some capital projects.

43. DRA would reduce this amount by $ 262,700 by eliminating increases requested for landscaping and water costs and by reducing hazardous waste handling cost/fees by $ 137,000.

44. Relying on 1988 recorded data, SDG&E and DRA agree on a test year expense forecast of $ 1,638,100 for overhead line expenses and $ 1,260,700 for underground line expenses.

45. The uncontested estimate for streetlight lamp outages, lamp replacements, and glassware replacements contained in both SDG&E and DRA's testimony is $ 216,700.

46. DRA reports that during a field investigation in January 1992 SDG&E acknowledged that its Field Service System project is still in the developmental stage and that the company is still trying to determine if it wants to continue with the project.

47. Although the record also supports denial of SDG&E's initial request for additional Turn-On-Meter workers, we remain concerned that the company not be deterred from taking relatively low cost steps [*198] that are likely to improve service.

48. DRA and SDG&E have both relied on adjusted 1988 recorded costs to produce an estimate for customer installation expenses of $ 1,926,700, adjusted to reflect costs related to staffing an electromagnetic fields (EMF) center.

49. The company's computerized mapping capability is an ongoing part of its distribution system operations.

50. While asserting that OMS will enable the company to process information faster during system disturbances, Mr. McNabb and the company had provided the Commission with no evidence demonstrating how the system would deliver its promise.

51. SDG&E states that it is seeking to maintain a two-year tree trimming cycle.

52. Historically, SDG&E performs preventive maintenance activities on a ten-year cycle.

53. SDG&E hopes that mail frequent preventive maintenance will reduce capital cost for replacement equipment and contribute to the corporate goal of improved electric reliability by reducing outages.

54. SDG&E cannot predict the extent to which outages will be reduced as a result of increased maintenance activities.

55. The effects of changing the preventive maintenance cycle will not be clear until the [*199] first new cycle is completed.

56. DRA recommends continued participation by SDG&E in the California Utility Exchange (CUE), a joint project among California energy utilities to maintain a common data base of new customers and delinquent customers for all utilities.

57. The settling parties agree to continue participation by SDG&E in the CUE program, providing that it remains cost-effective.

58. The record supports adoption of a company-wide estimate of postage expenses equaling $ 3,643,044.

59. The parties have agreed that LIRA expenses would be deferred for review in the reasonableness portion of the ECAC and BCAP proceedings.

60. DRA recommends using an uncollectible account rate of 0.274% which it states reflects inclusion of year-end 1991 data in the company's model.

61. There is no way to determine what expenses are included in Account 905.

62. SDG&E assigns account executives to major commercial and industrial customers to provide assistance with all their energy service needs.

63. In its testimony, DRA argued that the cost of providing special attention to particular customers should not be borne by ratepayers.

64. In the settlement agreement, the parties [*200] propose that SDG&E receive revenue requirement including $ 1,620,000 for the Major Account Executive program.

65. SDG&E's request for funding through Account 912 rather than Account 903 led to the impression that these expenses are related to DSM programs.

66. For future periods, SDG&E will charge the costs of customer service for large customers to Account 903.

67. For most A&G accounts, the parties have relied on what they describe as a widely accepted method for deriving the allocation percentages to apply to the distri-

bution of A&G expenses, resulting in an allocation of 74.56% to electric, 25.19% to gas, and 0.25% to steam.

68. The total proposed budget estimate for A&G salaries is $ 19,333,000.

69. SDG&E states that it first subtracted from its $ 1,400,000 1988 recorded A&G salary expenses to reflect "accounting adjustments and non-A&G charging" and then added $ 980,000 for positions that were "added in resource planning, pricing, legal, and human service areas reflecting new functions in regulatory requirements."

70. SDG&E has not explained how many positions it is adding under any of the its A&G categories, how much the new employees will be paid, or why any and [*201] all of the new positions are necessary.

71. DRA recommends an electric department Account 920 expense level of $ 17,653,000, with the difference of $ 1,680,000. stemming from DRA's proposal that all expenses related to incentive compensation program plans be borne by shareholders, not ratepayers.

72. The proposed settlement does include revenues for the Senior Management Incentive Compensation Plan.

73. SDG&E's affirmative showing in this case includes not a single word describing or discussing the Senior Management Incentive Compensation Plan.

74. DRA is of the opinion that there is a close relationship between expenditures for salaries (reflected in Account 920) and those for office supplies and expenses (as reflected in Account 921).

75. The settlement proposes adoption of the uncontested forecast of $ 4,194,000 for expenses related to professional consultants and others (such as accountants, auditors, actuaries, and lawyers) for general services not specifically applicable to other accounts.

76. The last year of recorded data offered (1988) indicates costs in Account 923 totalling $ 1 million.

77. Without explanation, SDG&E offers its estimate of $ 4,296,000 property [*202] insurance for 1993.

78. DRA based its estimate of $ 3,497,000 for this account on an eight-year average, citing the cyclical nature of insurance premium expense.

79. The settlement includes a proposal that a budget of $ 3,797,000 be adopted for Account 924.

80. DRA argues that directors' and officers' liability insurance costs must be shared, at least equally, between shareholders and ratepayers.

81. The Commission approved full recovery of directors' and officers' insurance in D.91-12-076 (SCE's general rate case decision).

82. The SCE general rate case decision issued last December did not address the question of shared responsibility for directors and officers insurance, thus, providing no guidance as how to resolve the issue as raised by DRA in this proceeding.

83. An open issue remains as to whether or not ratepayers should bear the full cost of insurance for directors and officers.

84. The company's total cost in 1990 for discretionary employee benefits was 9.7% of its straight time payroll.

85. According to SDG&E, it has held its benefits costs below the average partially through a greater degree of cost sharing by employees and partially by holding the line [*203] and benefit enhancements.

86. Company-wide, SDG&E's forecasts for employee pension and benefit expenses in 1993 is $ 42,404,000.

87. DRA recommended a $ 10,281,000 reduction to this request.

88. For the purposes of the settlement, the parties propose an electric benefits forecast expenditure of $ 24,444,000.

89. The settling parties report that this figure reflects the PBOP expense level being limited to the pay-as-you-go basis, however, it is not possible to determine how much of the reduction in revenue requirement results from the PBOP pay-as-you-go basis and how much results from the compromises apparently struck on the other issues.

90. It is unclear why it is reasonable to adopt a figure that reflects a compromise between the premium, budget, claim, and expense data utilized by SDG&E and the more recent data utilized by DRA.

91. For the purposes of the settlement, the parties agree on a forecast of $ 4,623,000 for regulatory expenses.

92. Year-to-year expense levels for internal electricity use are fairly consistent.

93. In the modified attrition settlement adopted in D.91-10-046, the parties agreed to a specific funding level for RD&D expenses in both 1992 and [*204] 1993.

94. The total forecast for electric department expenses in Account 930 is $ 11,025,000.

95. SDG&E requests $ 6,004,000 for RD&D expenditures in 1993.

96. The modified attrition settling parties agreed that SDG&E must return to ratepayers any portions of the $ 3,600,000 amount approved for EPRI dues but not paid to EPRI during 1992.

97. Since the end of 1992 is yet to arrive, it is too soon to determine whether or not the projected level of EPRI dues will be achieved.

98. The settlement agreement was silent as to the RD&D programs that would be funded during 1993.

99. SDG&E presented a revised RD&D planning document as part of its showing in the update hearings reportedly including program changes in response to concerns raised by DRA in its testimony, while proposing no change in the level of overall funding.

100. The revised RD&D planning document did not provide a breakdown of planned expenditures by year.

101. The California Energy Commission, which is not a party to the settlement agreement, proposes that the Commission approve a larger RD&D budget, directing SDG&E to augment its plan by including increased funding for an advanced gas turbine project and [*205] funding for participation in a multi-party solar thermal electric project.

102. SDG&E has declined to adopt the Energy Commission's recommendation and the other signatories to the settlement agreement have spoken in support of the company.

103. SDG&E has now committed $ 100,000 from its 1993 RD&D allocation to support its involvement in the advanced gas turbine project, and indicates that this level of involvement will be sufficient to assure full participation including voting rights.

104. The projects presented by the Energy Commission appear fully worthy of participation, but so do the projects proposed by SDG&E.

105. The revised RD&D plan fails to address a number of recommendations contained in the DRA report.

106. The settlement is silent on the issue of the appropriate RD&D funding range to adopt for SDG&E's next general rate case proceeding.

107. In D.91-12-076 (the Edison rate case), the Commission called for the setting of funding range criteria in R.87-10-013 (the RD&D rulemaking).

108. From 1989 through 1991, SDG&E's research funding, excluding the nondiscretionary tariff to the Gas Research Institute, ranged from 0.31 to 0.33% of the company's annual gross [*206] operating revenues.

109. The company maintains that it needs funding in the range of 0.30 to 0.45% in order to implement a meaningful RD&D plan.

110. The company maintains, and DRA agrees, that this range will allow for the budget to reflect flexibility suggested in D.90-09-045 and would also allow for changes in the operating environment.

111. In the proposed settlement, the parties agree to adopt the uncontested company forecast of $ 2,383,000 for maintenance of general plant.

112. The methodology to be used for calculating taxes in this proceeding is not controversial.

113. SDG&E and DRA have agreed upon a methodology for calculating depreciation that is reasonable for the purposes of this settlement.

114. SDG&E originally sought a five-year amortization of preliminary engineering and licensing service costs for three projects that it has now abandoned: The South Bay Unit 3 Clean Air Project, the Combined Cycle Project, and the California-Oregon Transmission Project (COTP).

115. DRA originally opposed the amortization of costs related to the South Bay Unit 3 and the Combined Cycle Projects.

116. In the settlement, parties have agreed to allow SDG&E to amortize all [*207] of the costs for each of these three facilities, although the period of amortization is extended to six years and does not allow for carrying costs related to these amounts.

117. SDG&E has presented evidence which, if fully litigated, would have provided the company with at least colorable arguments for some recovery through amortization.

118. DRA has also presented a substantial showing that would argue against recovery for the Combined Cycle and South Bay Projects.

119. It would be reasonable for a settlement to include some level of recovery to reflect the relative litigation risks inherent when there are arguments to be made by both sides.

120. The settlement offered in this instance allows for full recovery.

121. SDG&E has not named or described the software products for which it seeks recovery, nor explained why their use is necessary or reasonable.

122. The settling parties have agreed to not include some unspecified portion of the company's estimated plant-in-service cost in the rate base calculations for this proceeding.

123. The settlement is silent as to the proposed treatment of the Esco cleanup costs.

124. The record does not support an assertion that [*208] the cleanup activities are either a prerequisite to an upgrade of the substation or in any way related.

125. In that there is no pending request to place any new plant held for future use into rate base, there is no need for the Commission to reconsider its 1988 guidelines at this time.

126. DRA's test year 1993 estimate of $ 28,549,000 in advances for construction is based on the actual end of year 1991 level of customer advances, adjusted by SDG&E's forecasted net change to advances in 1992 and 1993.

127. SDG&E's estimate of $ 42,507,000 for Materials and Supplies was developed by taking the August 1991 recorded level of $ 41,654,169 and adjusting it to reflect expected increases in the cost of general supplies.

128. The company's working cash estimate of $ 7,916,000 reflects an agreement between the company and DRA for the Electric Department, as stated in the joint petition for modification of D.91-05-028.

129. The economic models used to determine the level of gas sales and customers are the same as those used for electric sales and customers.

130. DRA's estimate of gas revenues is derived by using billing determinants which come from DRA's customer and sales forecasts, [*209] which have also been adopted.

131. DRA's proposal for miscellaneous gas revenues closely parallels DRA's recommendation which relies on more current historical data and includes a forecast for gains from the disposition of gas plant (a factor that was not addressed by SDG&E).

132. DRA calculated its forecast for gas supply expenses using more recent recorded data than that relied on by SDG&E and produced nearly identical results.

133. Almost all of the difference between SDG&E's forecast of $ 193,300 and DRA's forecast of $ 86,000 for Account 840 relates to hazardous waste cleanup assessment studies that need to be performed at three Towngas sites and at the decommissioned old Chula Vista LNG site.

134. Consistently, the forecasts prepared by DRA and SDG&E for gas transmission expenses support each other.

135. Consistently, DRA's multi-year averaging technique produced estimates for gas distribution expenses that were sufficiently close to those produced by the company to lend support to the initial request.

136. There is no difference between the settling parties and either the methodology or rates used to depreciate gas department plant-in-service.

137. SDG&E's estimate [*210] of weighted gas plant additions for 1993 amounting to $ 23,007,000 is not cited in the record, nor does SDG&E itemize the costs related to the components of its plant additions estimate.

138. DRA and SDG&E utilize the same methodology for developing forecasts for customer advances and have produced virtually identical results.

139. In a manner consistent with the determination of working capital for the electric department, DRA and SDG&E have proposed the adoption of the uncontested amount of $ 3,365,000 for test year 1993.

140. Until late 1989, boilers located at the company's Station B were operated to produce the steam which was subsequently expanded through the house turbine to reduce the pressure of the steam for delivery to the customers.

141. During 1989, two package boilers were installed at Station B to produce the steam and to allow the less efficient boilers to be shut down.

142. SDG&E is in the process of making a transition out of the business of providing steam heat.

143. The company has established its steam sales forecast by conducting a survey of its steam customers.

144. There is no evidence supporting SDG&E's proposed use of a 1984 to 1988 averaging [*211] approach to derive a forecast for steam heat expenses.

145. Using the same pre-1989 approach, SDG&E forecasts its steam heat maintenance expenses to be $ 243,200 during the test year.

146. Using the 1989 and 1990 data, DRA produced virtually identical results.

147. DRA's estimate for steam heat plant-in-service is virtually identical to that prepared by SDG&E, even though the company did not have the benefit of end-of-the-year recorded information for its forecast.

148. Productivity measurement as it has been performed by SDG&E and DRA, involves the development of a ratio of outputs (kilowatt hours and therms) to inputs (ratepayer dollars).

149. The company concluded that the revenue requirement requested in the current application reflects compounded productivity gains of 8.2% since 1988.

150. The company bases over 40% of its forecasted expense on costs recorded in 1988.

151. This utility may be almost uniquely in a position to have accomplished substantial new efficiencies in the last five years.

152. SDG&E has 200 fewer employees today than it did just prior to the merger process.

153. The productivity analysis offered by the company and affirmed by DRA provides [*212] no basis for us to determine if the company has appropriately captured, in its base rates revenue requirement, the efficiencies gained during the last five years.

154. Neither does it allow us to determine that the company has improved its operations and cut its costs as it should have in response to its unique situation.

155. The company's productivity analysis focuses not on O&M and other costs that are the subject of this proceeding, but on all of the company's costs, including fuel costs that are reviewed in ECAC and BCAP proceedings.

156. An excessively high Test Year forecast could overshadow and defeat the benefits of earlier productivity gains.

157. The Settlement Agreement is largely silent on the issue of productivity.

158. If there are any benefits to have come from the years spent in planning for and advocating the since-rejected merger, they should be in the form of efficiencies that were gained by the company during a period of intense self-reflection.

159. The company's productivity analysis is limited to a study of the Electric Department.

160. Gain Sharing awards are paid to employees when actual O&M or capital expenditures are less than originally budgeted [*213] for a given purpose, or when customer satisfaction goals are exceeded.

161. In 1988 alone, the Gain Sharing program resulted in rewards to employees exceeding $ 4 million.

162. The 10% Solution is an employee suggestion plan in which employees are rewarded by receiving 10% of the first year's annual cost savings stemming from improvements that are implemented as a result of their suggestions.

163. SDG&E reports that the employee suggestion program has generated nearly $ 12 million of first-year annual cost savings.

164. The settlement includes a proposal that SDG&E be allowed to continue to receive, for at least another three years, a portion of the revenues needed to cover these expenses that no longer exist due to the Gain Sharing program and 10% Solution.

165. One of the major reasons for adhering to a three year rate case plan is to encourage each utility to streamline its operations where appropriate, with the promise of being able to retain any resulting savings that accumulate before the next general rate case comes along.

166. The parties recommended a 1993 Test Year total DSM funding level of $ 58.2 million (in 1993 dollars).

167. The parties recommend that [*214] the company be allowed a certain amount of flexibility in deciding how to spend its DSM budget.

168. There is uncertainty as to whether and when an Energy Technology Center will be created.

169. By designing a system of eight program categories, and by limiting fund shifting to changes within a given category, the system appears designed to maintain the overall priorities suggested by the spending plan before us.

170. The S-curve proposal for DSM rewards is based on internal assumptions and calculus that may not be readily accessible to many reviewers within or outside of the Commission.

171. While the record offers explanations for the relative differences among the types of incentives available for the company, we are not convinced an adequate showing has been made regarding the overall level of incentives resulting from the proposal.

172. We expected the parties to have analyzed the relative risks and associated returns commensurate with the proposed investment in DSM programs. The interim guidelines include a supply-side comparability feature, but we expect to fully explore the implications of this feature in the context of the rulemaking taking into account the experience [*215] with the joint proposal adopted in this proceeding.

173. The Joint recommendation reflects the maximum allowable incentive level within current guidelines.

174. We have committed ourselves to supporting a long-term effort by our regulated energy utilities to support DSM activities and these programs have yet to mature.

175. The incentive process as a whole remains, at this phase, an experiment, the results of which could ultimately lead to dramatic changes to the incentive approach or the elimination of incentives altogether.

176. We have not formed a commitment to continue the use of S-shaped curves or determined that current incentive levels are appropriate to the tasks at hand.

177. SDG&E currently counts DSM achievements at the time a contract is signed with the customer, not at the time of equipment installation.

178. The Commission has ordered in the DSM OIR/OII that the value of DSM savings be determined on an ex post basis beginning in 1994.

179. SDG&E proposed a transition mechanism to change to counting DSM savings at the time of installation in 1993.

180. The transition mechanism may create conflicting incentives.

181. A transition of this type is [*216] likely to make only the most marginal of differences.

182. A gradual transition from rewards for signing contracts to rewards for achieving installations does not appear to be necessary.

183. Although a major reason for the transition is to help stabilize the reward payments to the company, it is not clear that the proposal would have that effect.

184. If there has to be a less than smooth transition (and we are not convinced there will be) then any aspect of the DSM earnings formula that could help hold rates down should take effect as soon as possible.

185. One way to help assure that DSM earnings do not bounce precipitously is to continue to amortize earnings over a three-year period.

186. In a report filed August 17, 1992, CACD found that most of SDG&E's 1991 savings from its 1989 GRC DSM program were reasonable and recommended a reward level of $ 7,558,200.

187. Since this amount exceeds the cap, SDG&E would be eligible for the full $ 7.15 million reward.

188. $ 1.6 million is requested for rate recovery in 1993 for SDG&E's 1991 program results under the collaborative shareholder incentive mechanism authorized in D.90-08-068.

189. The 1990 reward of $ 2.1 million [*217] was approved in Decision 91-10-046 in SDG&E's 1992 Modified Attrition Application.

190. In its report concerning the 1991 operation of the GRC DSM program, CACD made many recommendations that may help improve the operation and flow of information related to future DSM activities.

191. CACD examined the debit that SDG&E proposed to apply to the 1991 GRC DSM reward for the cancellation of contracts that were signed in 1989.

192. CACD recommended that the 1989 contract reward amount be escalated to 1991 dollars using the 1989 GRC's DSM escalation value before subtracting out the cancellations.

193. DRA recommended that both the 1989 cancelled contract reward amount and the 1991 reward amount be escalated to 1993 dollars and the subtraction be made at that point.

194. UCAN argues that it is not enough to only adjust the rewards received for cancelled contracts by an inflation factor; the ratepayer's lost investment opportunity should also be reflected.

195. There is no logical reason to apply a reduction related to the 1989 reward to SDG&E's 1991 reward calculation.

196. SDG&E received its reward for these cancelled 1989 contracts through rates in 1991.

197. SDG&E has [*218] proposed to terminate its EEBA, GEBA and corresponding offset rates at the end of 1992.

198. SDG&E claims that early termination of the offset rates will result in an undercollection of $ 10 million in electric and $ 6 million in gas revenues.

199. Because the figures for both expenditures and revenue collection are presented here only as estimates, some accommodation must be made for actual under- or overcollection through December 31, 1992.

200. $ 4,054,000 should be recovered in the GEBA and would be undercollected in 1992.

201. Since there has been no audit of SDG&E's gas DSM programs, we have no assurance that the company's figures are accurate or that it has used its available funds in a manner consistent with our previous orders.

202. We find it beneficial to zero-out and preclude further use of the GEBA, as well as the EEBA, but cannot allow the collection of an extra $ 2.03 million without an audit.

203. With the support of UCAN and DRA, the City strongly objects to SDG&E's long-standing habit of illuminating the exterior of its corporate headquarters with floodlights.

204. Some of the area's residents are deeply offended by the company's lighting display.

205. [*219] At least some downtown landlords and business associations like to have the floodlights burning, out of a sense that they enhance the safety in the downtown area.

206. During each oil crisis, SDG&E voluntarily turned off the lights and boasted that this act communicated to the community the company's strong desire to encourage energy conservation without compromising safety in the downtown area.

207. At least to some people, a brightly lit yet largely vacant building communicates some form of indifference to the effects of impulsive energy consumption.

208. It appears that while SDG&E encourages its other commercial and industrial customers to undergo energy audits, it has not undertaken a similar analysis of its own corporate headquarters.

209. In D.92-09-080 in the DSM rulemaking proceeding, we adopted SDG&E's proposal to put out its residential appliance efficiency program for bid by third parties.

210. Pursuant to Ordering Paragraph 9 of D.92-09-080, SDG&E is authorized to recover in rates over 3 years a total of $ 19,599,159 (1993 $) for its residential appliance efficiency incentives program and associated measurement activities.

211. CACD issued a Report on SDG&E's [*220] program costs entitled "Audit Report on the Emerging Business Enterprises Program Costs of San Diego Gas & Electric Company for 1993 Test Year".

212. DRA and SDG&E propose that the revenue increase of $ 274,900 (1988$) recommended in that report be added to the revenue requirement identified in the Settlement Agreement.

213. The Settlement Agreement proposes that $ 4,922,000 (1993 $) should be added for each additional SONGS refueling expected in 1993 in addition to the one refueling already included for Unit 2.

214. We still have no firm indication that SCE currently plans to undertake two refueling outages in 1993.

215. The settling parties propose that appropriate administrative costs for the LIRA program should continue to be recorded in the LIRA balancing account and recovered through SDG&E's ECAC and BCAP proceedings.

216. The settling parties propose that intervenor fee compensation awards be recorded in ECAC and BCAP balancing accounts and be recovered through those respective proceedings.

217. Although the utility proposes that some costs related to natural gas vehicle development be included in its RD&D budget, the Settling Parties propose that the recovery [*221] of other costs related to natural gas and electric vehicle activities be deferred to the LEV investigation (I.91-10-029).

218. A funding gap may exist between the end of the natural gas vehicle development program authorized in D.91-07-017 and funding that may arise pursuant to the LEV investigation (I.91-10-029).

219. There are logical reasons to continue the practice of allowing the utility to track hazardous waste cleanup costs through memorandum accounts.

220. We are not willing, however, to allow the company to extend the advice letter process to cover other costs that it describes as being related to environmental compliance.

221. Because such environmental compliance costs should be reflected in the planning process and carefully controlled, they should be approved in advance.

222. The record does not include adequate information to allow for approval of funds for environmental compliance activities during the prospective rate case cycle.

223. We expect this company and all other utilities to take reasonable steps to minimize the generation of hazardous wastes through the use of efficient processes, reuse, recycling and appropriate chemical substitution.

224. [*222] The Settlement Agreement is supported by each if the parties who were actively involved in Phase I, with the exception of the CEC, which only participated concerning a limited RD&D issue.

225. UCAN is eligible to claim intervenor compensation.

Conclusions of Law

1. The Settlement Agreement is reasonable.

2. While SDG&E should have the discretion to devote a portion of its RD&D budget to the Solar 2 project and increase its contribution to the advance gas turbine project, the Commission should not require the company to do so.

3. SDG&E should return to ratepayers any amounts forecast for payments to EPRI in 1992 or later years that were not spent for that purpose.

4. SDG&E should provide a report on its actual EPRI expenditures in 1992 as part of its next attrition filing.

5. For the purposes of its next rate case cycle, SDG&E should be allowed to make RD&D expenditures that fall within the range of 0.30 to 0.45% of its annual gross operating revenues.

6. As part of its next attrition filing, SDG&E should report on its efforts to improve inter-utility RD&D coordination as recommended by DRA and CACD in this proceeding.

7. As part of the next attrition filing, [*223] SDG&E should provide a report quantifying royalties and licensing fees stemming from RD&D results that it is required, pursuant to the last modified attrition proceeding settlement, to return to ratepayers.

8. As part of its next attrition filing, SDG&E should include a report indicating the steps that it has taken to implement each of the recommendations included in DRA's report on RD&D.

9. While cost savings generated during the rate case cycle from approaches such as the Gain Sharing program and the 10% Solution can be retained by shareholders, the adopted forecast for the subsequent test year should be adjusted to reflect any resulting lower costs.

10. It continues to be Commission policy that public relations advertising costs will not be borne by ratepayers.

11. With the exception of modifications specifically mentioned in this order, the Joint Recommendation of SDG&E, DRA, and UCAN for DSM programs should be adopted.

12. The proposed funding for an Energy Resource Center should be denied.

13. SDG&E should be allowed to file an advice letter requesting memorandum account treatment for initial costs related to an Energy Resource Center once the company has a firm plan [*224] for the center in place.

14. The mechanisms proposed in the Joint DSM Recommendation for a transition from time-of-contract incentives to time-of-installation incentives and from incentive caps to no incentives caps should be rejected.

15. All DSM shareholder incentive payments should be amortized over a three-year period.

16. The revenue requirement should be reduced to reflect a refund of incentive payments received by shareholders for 1989 DSM contracts that were subsequently cancelled.

17. The revenue reduction for this purpose should be calculated by adjusting the nominal refundable reward payment in the manner described in this opinion.

18. The DSM offset rates should be eliminated.

19. The GEBA and EEBA balancing accounts should be zeroed-out in the manner described in this opinion.

20. While the Commission should not order SDG&E to cease using flood lights to illuminate its corporate headquarters, we should encourage SDG&E to reconsider its current lighting policy in response to the concerns raised by the City of San Diego and work with the City in crafting a solution to its concerns.

21. SDG&E should order an energy audit of its corporate headquarters and [*225] produce, for the next attrition proceeding, a report containing the auditor's recommendations and the company's implementation plan.

22. The adopted revenue requirement forecast should include the cost of the company's DSM pilot bidding program as approved in D.92-09-080.

23. CACD's recommended modifications to SDG&E's DSM procedures, as set forth in CACD's Report on SDG&E 1991 Demand-Side Management Evaluation and discussed in this opinion should be adopted.

24. The proposal included in Joint DSM Recommendation for revising the procedures for review of advice letter filings requesting DSM program changes should be rejected.

25. The revenue requirement increase recommended in CACD's Audit Report on the Emerging Business Enterprises Program Costs should be adopted.

26. SDG&E should be authorized to continue the memorandum account treatment for its natural gas vehicle development program as authorized in D.91-07-017 subsequent to the expiration date of the account to insure continuation of the program at current annual funding levels pending a Commission decision in the ongoing LEV investigation (I.91-10-029).

27. SDG&E should be allowed to continue to track hazardous waste [*226] cleanup through memorandum accounts when authorized in response to an advice letter filing under existing rules.

28. SDG&E should not be allowed to capitalize hazardous waste cleanup costs in the absence of specific approval from the Commission.

29. In that the settlement does not specifically propose capitalization of past hazardous waste cleanup costs associated with the Esco site and the Commission has not otherwise approved capitalization of those costs, such costs should not be recorded in the company's plant-in-service.

30. A hazardous waste minimization audit should be performed as discussed in this opinion, the results of which should be presented in the company's next general rate case proceeding.

31. The use of a memorandum account to track other types of environmental compliance costs, although allowed during the 1992 modified attrition year, should not be continued.

32. Requests for funding related to environmental compliance activities should be made in general rate cases, attrition filings, or other applications.

33. As part of its attrition filing, SDG&E should prepare a report (subject to review and approval or rejection by the Commission) signed by a representative [*227] of each settling party, that identifies and quantifies each project disallowed from beginning-of-year 1992 plant-in-service, 1992 plant additions, and forecasted 1993 plant additions in a manner consistent with the rate base amounts included in the settlement agreement.

34. UCAN should be found eligible to claim intervenor compensation.

35. UCAN should be allowed to request compensation for Phase I participation prior to the completion of Phase II.

36. So that the new interim rates can become effective on January 1, 1993, this order should be made effective today.

ORDER

IT IS ORDERED that:

1. San Diego Gas & Electric Company (SDG&E) shall, on or before December 21, 1992, file with this Commission revised tariff sheets which:

a. Revise its authorized level of base rate revenue as set forth in Appendix B to this decision;

b. Revise its authorized revenue allocation and rate design as set forth in Appendices K, L, and M; and

c. Make other revisions as necessary to comply with this interim order.

2. The revised tariff pages shall become effective January 1, 1993 and shall comply with General Order 96-A. The revised tariffs shall apply to service rendered on or after [*228] their effective date.

3. The Settlement Agreement sponsored by SDG&E, the Division of Ratepayer Advocates (DRA), the Utility Consumer Action Network (UCAN), and the City of San Diego (City) and attached to this opinion as Appendix N is adopted, subject to the limitations and interpretations discussed in the Joint Comparison exhibit and this opinion and to the following conditions:

a. As part of its attrition filing, SDG&E shall prepare a report (subject to review and approval or rejection by the Commission) signed by a representative of each settling party, that identifies and quantifies (in a manner consistent with the rate base amounts included in the settlement agreement) each project disallowed from beginning-of-year 1992 plant-in-service, 1992 plant additions and forecasted 1993 plant additions.

b. As part of its next attrition filing, SDG&E shall include a report indicating the steps that it has taken to implement each of the recommendations included in DRA's Report on RD&D in this proceeding, as well as providing more detailed RD&D budget information as discussed herein.

c. Unless otherwise specified, memorandum accounts shall not be used to track environmental compliance [*229] costs other than hazardous waste cleanup costs for which appropriate advice letters have been filed and approved. Requests for funding related to other environmental compliance activities shall be made in general rate cases, the 1994 modified attrition filing, or other applications.

d. SDG&E shall provide a report on its actual 1992 EPRI expenditures as part of its next attrition filing and shall return to ratepayers any forecasted amounts that were not spent for that purpose.

e. As part of its next attrition filing, SDG&E shall provide a report quantifying royalties and licensing fees stemming from RD&D results which it is required, pursuant to the last modified attrition proceeding settlement, to return to ratepayers.

f. As part of its next attrition filing, SDG&E shall report on its efforts to improve inter-utility RD&D coordination as recommended by DRA and CACD in this proceeding.

g. Whether or not specifically discussed in this opinion, the treatment of each and every principle or issue addressed in the settlement is non-precedential in this or any other future proceeding, consistent with Rule 51.8 of the Commission's Rules of Practice and Procedure.

4. SDG&E may [*230] elect to devote a portion of the RD&D budget approved in this opinion to the Solar 2 project and/or increase its contribution to the advance gas turbine project, if such an election is consistent with this Commission's rules concerning RD&D expenditures. However, the company is not required to do so.

5. For the purposes of its next rate case cycle, SDG&E is allowed to make RD&D expenditures that fall within the range of 0.30 to 0.45% of its annual gross operating revenues.

6. While cost savings generated during the rate case cycle from efforts such as the Gain Sharing program and the 10% Solution may be retained by shareholders, the adopted forecast for the subsequent test year shall be adjusted to reflect any resulting cost reductions.

7. Public relations advertising costs shall not be borne by ratepayers.

8. With the exception of modifications described in this opinion and/or itemized in this Ordering Paragraph, the Joint Recommendation of SDG&E, DRA, and UCAN for DSM programs is adopted:

a. The proposed funding for an Energy Resource Center is denied. SDG&E may file an advice letter requesting memorandum account treatment for initial costs related to an Energy Resource [*231] Center once the company has a firm plan for the development of the center.

c. The mechanisms proposed in the Joint DSM Recommendation for a transition from time-of-contract incentives to time-of-installation incentives and from incentive caps to no incentives caps are denied.

d. All DSM shareholder incentive payments shall be amortized over a three-year period.

e. The proposed revision of the procedures for review of advice letter filings requesting DSM program changes is denied.

9. The revenue requirement shall be adjusted to include one-third of the maximum incentive payment allowed for DSM efforts in 1991.

10. The revenue requirement shall be reduced to reflect a refund of incentive payments received by shareholders for 1989 DSM contracts that were subsequently cancelled. This reduction shall be calculated by adjusting the nominal refundable reward payment in the manner described in this opinion.

11. The adopted revenue requirement shall include the cost of the company's DSM pilot bidding program as approved in D.92-09-080.

12. The DSM offset rates are eliminated.

13. The balances in the Gas Efficiency Balancing Account and Electric Efficiency Balancing Account [*232] shall be reduced in the manner described in this opinion.

14. While the Commission will not order SDG&E to cease using flood lights to illuminate its corporate headquarters, we encourage SDG&E to reconsider its current lighting policy in response to the concerns raised by the City of San Diego and work with the City in crafting a solution to its concerns.

15. SDG&E shall order an energy audit of its corporate headquarters and produce, for the next attrition proceedings, a report containing the auditor's recommendations and the company's implementation plans.

16. CACD's recommended modifications to SDG&E's DSM procedures, as set forth in CACD's Report on SDG&E 1991 Demand-Side Management Evaluation and discussed in this opinion, are adopted.

17. The additional revenue requirement increase recommended in CACD's Audit Report on the Emerging Business Enterprises Program Costs is adopted.

18. SDG&E is authorized to continue the memorandum account treatment for its natural gas vehicle demonstration program as authorized in D.91-07-017 subsequent to the expiration date of the account to insure continuation of the program at current annual funding levels pending a Commission decision [*233] in the ongoing Low Emission Vehicle investigation (I.91-10-029).

19. In the absence of specific approval from the Commission, SDG&E shall not capitalize hazardous waste cleanup costs.

20. The settlement adopted above does not specifically propose capitalization of past hazardous waste cleanup costs associated with the Esco site and the Commission has not otherwise approved capitalization of those costs. Therefore, such costs shall not be recorded in the company's plant-in-service.

21. A hazardous waste minimization audit shall be performed as discussed in this opinion, the results of which should be presented in the company's next general rate case proceeding.

22. In future rate case, SDG&E will be expected to improve its productivity analysis in a manner consistent with the discussion in this opinion.

23. UCAN is eligible to request intervenor compensation.

24. UCAN may request compensation for its Phase I participation separate from Phase II.

This order is effective today.

Dated December 3, 1992, at San Francisco, California.

APPENDIX A

Applicant: David R. Clark, William L. Reed, Keith W. Melville, Vicki Thompson, Attorneys at Law, and Lee Schavrien, for [*234] San Diego Gas & Electric Company.

Interested Parties: Peter V. Allen, Attorney at Law, for the City of San Diego; Patrick J. Bittner, Attorney at Law, for the California Energy Commission, Morrison & Foerster, by Jerry R. Bloom and Joseph M. Karp, Attorneys at Law, for the California Cogeneration Council; Maurice Brubaker, for Drazen-Brubaker & Associates; McCracken, Byers & Martin, by David J. Byers, Attorney at Law, for the California City-California Street Light Association; John M. Edwards, for Sithe Energies, Inc.; Norman Furuta, Attorney at Law, for Federal Executive Agencies; Steven Geringer, Attorney at Law, for California Farm Bureau Federation; Grueneich, Ellison & Schneider, by Dian Grueneich, Attorney at Law, and Matt Brady, for California Department of General Services; Biddle & Hamilton, by Richard L. Hamilton, Attorney at Law, for Western Mobilehome Association; Gerald L. Hein, for General Atomics; James Hodges, for Campesinos Unidoes, Inc. and the Metrolitan Area Advisory Commission; Harry W. Long, Jr., Kermit R. Kubitz, Robert McClennan, Attorneys at Law, and Mike Apra, for Pacific Gas and Electric Company; [*235] Barry J. Lovell, for University Cogeneration, Inc.; William Marcus and Jeff Nahigian, for JBS Energy; Melissa Metzler, for Barakat & Chamberlin; Julie Miller, Attorney at Law, for Southern California Edison Company; Mayor Tim Nader, by Dan Beintema, for the City of Chula Vista; Edward J. Neuner, for himself; Steven D. Patrick and Nancy Day, for Southern California Gas Company; Donald G. Salow, for the Association of California Water Agencies (ACWA); Reed V. Schmidt, for Bartle Wells Associates; Michael Shames, for Utility Consumers Action Network (UCAN); Tom Trimble and Terry Campbell, for Winfield Industries; Paul A. Weir, for San Diego Mineral Products Industry (MPI) Coalition; and Levy, Samrick & Bernard, by Patrick O'Donnell, Attorney at Law, for California Travel Parks Association.

Commission Advisory and Compliance Division: Scarlett C. Liang-Uejio.

Division of Ratepayer Advocates: Philip Scott Weismehl, Catherine Johnson, Attorneys at Law, David Fukutome, and Darlene Clark.

APPENDIX B

SAN DIEGO GAS & ELECTRIC COMPANY

Test Year 1993

SUMMARY OF EARNINGS

COMBINED DEPARTMENT

(Thousands of 1993 Dollars)

Description	SDG&E Estimated	Adopted
Operating Revenues		
Base Rate Revenues - Retail	$ 1,129,080	$ 1,095,770
Interdepartmental	11,901	11,901
Miscellaneous	17,861	17,861
Non-Jurisdictional	1,375	1,375
Total Operating Revenues	$ 1,160,217	$ 1,126,907
Operating Expenses		
Supply	594	594
Storage	279	279
Production	122,763	122,686
Transmission	16,847	16,848
Distribution	63,045	63,046
Customer Accounts	45,957	45,958
Uncollectibles	3,090	2,998
Demand-Side-Management	56,810	53,810
Marketing (Non-DSM)	0	0
Administrative & General	111,335	113,306
Franchise Requirements	22,208	21,555
Other Adjustment	(2,182)	(2,183)
Subtotal	$ 440,747	$ 438,896
Depreciation	222,860	222,860
Taxes Other Than On Income	47,884	47,805
Taxes On Income	152,004	142,981
Total Operating Expenses	$ 863,495	$ 852,542
Net Operating Income	$ 296,722	$ 274,365
Rate Base	$ 2,760,210	$ 2,760,210
Rate of Return	10.75%	9.94%
DSM 1990 & 1991 Rewards (Incl. FF&U)	$ 9,735	$ 3,899
DSM Balancing Account Amort. (Incl. FF&U)	$ 17,073	$ 5,691
10/91-12/91 DSM Collaborative	$ 507	$ 507
TOTAL AUTH. BASE RATE REVENUES (ABRR)	$ 1,168,296	$ 1,117,769
Change in Base Rate Rev.	$ 118,377	$ 67,850
	11.27%	6.46%

[*236]

SUMMARY OF EARNINGS

ELECTRIC DEPARTMENT

(Thousands of 1993 Dollars)

Description	SDG&E Estimated n1	Adopted
Operating Revenues		
Base Rate Revenues - Retail	$ 961,926	$ 932,642
Miscellaneous	15,057	15,057
Non-Jurisdictional	1,375	1,375
Total Operating Revenues	$ 978,358	$ 949,074
Operating Expenses		
Production	122,048	121,970
Transmission	10,962	10,962
Distribution	41,819	41,819
Customer Acctounts (Incl. Engy. Serv.)	30,144	30,144
Uncollectibles	2,636	2,555
Demand-Side-Management	46,841	44,140
Marketing (Non-DSM)	0	0
Administrative & General	83,346	84,766
Franchise Requirements	18,565	18,000
Other Adjustment	(1,575)	(1,575)
Subtotal	$ 354,787	$ 352,782
Depreciation (Incl. Nucl. Decomm.)	193,470	193,470
Taxes Other Than On Income	40,763	40,705
Taxes On Income	131,985	124,156
Total Operating Expenses	$ 721,005	$ 711,112
Net Operating Income	$ 257,353	$ 237,962
Rate Base	$ 2,393,984	$ 2,393,984
Rate of Return	10.75%	9.94%
DSM 1990 & 1991 Rewards (Incl. FF&U)	$ 8,269	$ 3,603
DSM Balancing Account Amort. (Incl. FF&U)	$ 10,184	$ 3,395
TOTAL AUTH. BASE RATE REVENUES (ABRR) n2	$ 980,379	$ 939,640
Change in Base Rate Rev. n3	$ 94,745	$ 54,006
	9.66%	5.75%

[*237]

n1 As Calculated in SDG&E's Updated Results of Oper. (Exh.64), which partially reflects the Settlement Agreements (Exh.6 & 50).

n2 Excluding miscellaneous & non-jurisdictional revenues.

n3 Based on present ABRR of $ 885,634 adopted in D.92-08-042.

SUMMARY OF EARNINGS

GAS DEPARTMENT

(Thousands of 1993 Dollars)

Description	SDG&E Estimated n1	Adopted
Operating Revenues		
Base Rate Revenues - Retail	$ 165,552	$ 161,520
Interdepartmental	11,901	11,901
Miscellaneous	2,804	2,804
Total Operating Revenues	$ 180,257	$ 176,225
Operating Expenses		

Description	SDG&E Estimated n1	Adopted
Supply	594	594
Storage	279	279
Transmission	5,885	5,886
Distribution	21,150	21,151
Customer Accounts (Incl. Engy. Serv.)	15,808	15,809
Uncollectibles	454	443
Demand-Side-Management	9,969	9,670
Administrative & General	27,659	28,196
Franchise Requirements	3,609	3,521
Other Adjustment	(594)	(594)
Subtotal	$ 84,813	$ 84,954
Depreciation	29,139	29,139
Taxes Other Than On Income	7,070	7,049
Taxes On Income	19,933	18,742
Total Operating Expenses	$ 140,955	$ 139,884
Net Operating Income	$ 39,302	$ 36,341
Rate Base	$ 365,601	$ 365,601
Rate of Return	10.75%	9.94%
DSM 1990 & 1991 Rewards (Incl. FF&U)	$ 1,466	$ 297
DSM Balancing Account Amort. (Incl. FF&U)	$ 6,889	$ 2,296
10/91-12/91 DSM Collaborative n2	$ 507	$ 507
TOTAL AUTH. BASE RATE REVENUES (ABRR) n3	$ 186,315	$ 176,521
Change in Base Rate Rev. n4	$ 23,656	$ 13,862
	12.70%	7.85%

[*238]

n1 As Calculated in SDG&E's Updated Results of Oper. (Exh. 64), which partially reflects the Settlement Agreements (Exh.6 & 50).

n2 As adopted in SDG&E's last BCAP Decision (D. 91-12-075).

n3 Excluding miscellaneous revenues.

n4 Based on present ABRR of $ 162,659 adopted in D.91-12-074.

SUMMARY OF EARNINGS

STEAM DEPARTMENT

(Thousands of 1993 Dollars)

Description	SDG&E Estimated n1	Adopted
Operating Revenues		
Base Rate Revenues - Retail	$ 1,602	$ 1,608
Miscellaneous	0	0
Non-Jurisdictional	0	0
Total Operating Revenues	$ 1,602	$ 1,608
Operating Expenses		
Production	715	715
Distribution	76	76
Customer Accounts	5	5

	SDG&E	
Description	Estimated n1	Adopted
Uncollectibles	0	0
Administrative & General	330	343
Franchise Requirements	34	34
Other Adjustment	(13)	(13)
Subtotal	$ 1,147	$ 1,160
Depreciation	251	251
Taxes Other Than On Income	51	51
Taxes On Income	86	84
Total Operating Expenses	$ 1,535	$ 1,546
Net Operating Income	$ 67	$ 62
Rate Base	$ 625	$ 625
Rate of Return	10.75%	9.94%
TOTAL AUTH. BASE RATE REVENUES (ABBR) n2	$ 1,602	$ 1,608
Change in Base Rate Rev. n3	($ 24)	($ 18)
	-1.49%	-1.12%

n1 As Calculated in SDG&E's Updated Results of Oper. (Exh. 64), which partially reflects the Settlement Agreements (Exh.6 & 50).

n2 Excluding miscellaneous revenues.

n3 Based on present ABRR of $ 1,626 adopted in D.91-12-074.

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DSM REWARDS AND BALANCING ACCOUNT AMORTIZATION

(Thousand of Nominal Dollars)

Description	1993	1994	1995	Total
1. Rewards:				
1991 GRC Programs:				
Electric	$ 1,907	$ 1,907	$ 1,907	$ 5,720
Gas	477	477	477	1,430
Total 1991 GRC Programs	$ 2,383	$ 2,383	$ 2,383	$ 7,150
1990 Collabrative Programs:				
Electric	700	700	--	$ 1,400
Gas	--	--	--	0
Total 1990 Collabrative Prog.	$ 700	$ 700	$ 0	$ 1,400
1991 Collabrative Programs:				
Electric	1,667	1,667	1,667	$ 5,000
Gas	--	--	--	0
Total 1991 Collabrative Prog.	$ 1,667	$ 1,667	$ 1,667	$ 5,000
Adjustment:				
1989 Cancelled Projects				
Electric (80%)	($ 750)	$ 0	$ 0	($ 750)
Gas (20%)	($ 187)	0	0	(187)
Total Adjustment	($ 937)	$ 0	$ 0	($ 937)
Total Rewards				
Electric	$ 3,524	$ 4,273	$ 3,573	$ 11,370
Gas	289	477	477	1,243
Total Rewards w/o FF&U	$ 3,813	$ 4,750	$ 4,050	$ 12,613

Description	1993	1994	1995	Total
Electric	$ 3,603	$ 4,370	$ 3,654	$ 11,626
Gas	297	489	489	1,274
TOTAL REWARDS INCL. FF&U	$ 3,899	$ 4,858	$ 4,143	$ 12,900
2. Balancing Account Amortization				
Electric Efficiency Bal. Acct. (EEBA)	$ 3,320	$ 3,320	$ 3,320	$ 9,960
Gas Efficiency Bal. Acct. (GEBA)	2,240	2,240	2,240	6,720
Total Bal. Acct. Amortization	$ 5,560	$ 5,560	$ 5,560	$ 16,680
EEBA	$ 3,395	$ 3,395	$ 3,395	$ 10,184
GEBA	2,296	2,296	2,296	6,889
TOTAL BAL. ACCT. AMORT. Incl. FF&U	$ 5,691	$ 5,691	$ 5,691	$ 17,074

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APPENDIX C

SAN DIEGO GAS & ELECTRIC COMPANY

Test Year 1993

ADOPTED SALES AND CUSTOMER FORECASTS

Description Electric Department	Sales (GWh)	Adopted n1 Customers
Residential	5,572	1,029,984
Commercial	5,610	116,810
Industrial	3,194	547
Agricultural Power	236	3,961
Street Lighting	67	1,540
Resale	0.2	1
Total	14,679	1,152,843

Description Gas Department	Sales (Mtherm)	Adopted n1 Customers
Residential	338,200	679,089
Non-Residential	352,800	28,029
Interdepartmental	384,100	--
Total	1,075,100	707,118

Description Steam Department	Sales (lbs) (000)	Adopted n1 Customers
Schedule 1	25,805	7
Schedule 2	0	0
	25,805	7

n1 As in the Settlement Agreement (Exh.50, APPENDIX E).

APPENDIX D

SAN DIEGO GAS & ELECTRIC COMPANY

Test Year 1993

ADOPTED ESCALATION RATES

(Base Year 1988)

	Labor		Non-Labor	
Year	Rate	Index	Rate	Index
1988	--	100.0	--	100.0
1989	3.82%	103.8	4.76%	104.8
1990	3.94%	107.9	3.55%	108.5
1991	4.51%	112.8	3.31%	112.1
1992	4.33%	117.7	2.17%	114.5
1993	3.47%	121.7	3.43%	118.4

APPENDIX E

SAN DIEGO GAS & ELECTRIC COMPANY

ELECTRIC [*241] DEPARTMENT

Test Year 1993

FRANCHISE FEES AND UNCOLLECTIBLES - ADOPTED RATES

(Thousands of 1993 Dollars)

Description	Adopted
Uncollectibles	
Adopted Base Rate Revenues - Retail	$ 932,642
Uncollectible Rate	0.2740%
Total Uncollectibles	$ 2,555
Franchise Requirements	
Adopted Base Rate Revenues - Retail	$ 932,642
Franchise Fee Rate	1.9300%
Total Franchise Fees	$ 18,000

TOTAL PRODUCTION EXPENSE

(Thousands of 1988 Dollars Unless Otherwise Indicated)

Description	Adopted
Operation	
Steam	$ 24,571
Nuclear	35,120
Other	322
Total Operation	$ 60,013
Maintenance	
Steam	14,483
Nuclear	26,943
Other	2,060

Description	Adopted
Total Maintenance	$ 43,486
Other Power Supply	$ 2,740
TOTAL PRODUCTION (1988$)	$ 106,239
Escalation Amounts, 1988 to 1993	
Labor	9,052
Non-Labor	6,680
Other	0
Total	$ 15,732
TOTAL PRODUCTION (1993$)	$ 121,970

STEAM PRODUCTION EXPENSE

(Thousands Of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Operation	
500.0	Oper. Supervision and Engineering	$ 3,348
501.0	Fuel Related Expenses	1,222
502.0	Operation of Boiler	3,669
505.0	Electric Oper. of Turbine	5,681
506.0	Misc. Steam Power Expenses	1,162
507.0	Rents	9,489
	Total Operation	$ 24,571
	Maintenance	
510.0	Maint. Supervision and Engineering	678
511.0	Maint. of Structures	4,575
512.0	Boiler Maint. & Overhaul	4,386
513.0	Turbine Maint. & Overhaul	3,914
514.0	Miscellaneous Equipment	930
	Total Maintenance	$ 14,483
	TOTAL STEAM PRODUCTION (1988$)	$ 39,054
	Escalation Amounts, 1988 to 1993	
	Labor	2,286
	Non-Labor	3,037
	Other	0
	Total	$ 5,322
	TOTAL STEAM PRODUCTION (1993$)	$ 44,376

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NUCLEAR PRODUCTION EXPENSE

(Thousands of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Operation	
517.0	Supervision and Engineering	$ 14,463
519.0	Coolants and Water	1,559
520.0	Operation of Reactor	4,824
523.0	Electric Expenses	543
524.0	Misc. Nuclear Power Expenses	13,542
525.0	Rents	189
	Total Operation	$ 35,120
	Maintenance	
528.0	Supervision and Engineering	8,102

Account No.	Description	Adopted
529.0	Structures	3,256
530.0	Maint. of Boilers	6,777
531.0	Boiler Overhaul	3,681
532.0	Maint. of Turbine	5,127
	Total Maintenance	$ 26,943
	TOTAL NUCLEAR PROD. (1988$) n1	$ 62,063
	Escalation Amounts, 1988 to 1993 n2	
	Labor	6,189
	Non-Labor	3,146
	Other	0
	Total	$ 9,335
	TOTAL NUCLEAR PROD. (1993$)	$ 71,397

n1 Including SDG&E's share of SONGS base & two refueling outage costs: $ 38,265 Labor, $ 20,832 Non-Labor, $ 2,539 Other (Total $ 61,636).

n2 Escalations for SDG&E's share of SONGS O&M expenses are calculated using SoCal Edison's escalation rates adopted in SCE's 1992 GRC decision (D.91-12-076, Appendix C, Page 1 of 1, Appendix E, Page 3 of 10).

GAS TURBINE POWER PRODUCTION & OTHER POWER SUPPLY

(Thousands Of 1988 Dollars Unless Otherwise Indicated) [*243]

Account No.	Description	Adopted
	Operation	
546.0	Supervision and Engineering	$ 11
547.0	Fuel Related Expenses	29
548.0	Generation Expenses	71
549.0	Misc. Other Power Expenses	150
550.0	Rents	61
	Total Operation	$ 322
	Maintenance	
551.0	Supervision and Engineering	145
552.0	Structures	160
553.0	Maint. of Gas Turbine	1,711
554.0	Misc. Other Power Gen. Plant	44
	Total Maintenance	$ 2,060
	Other Power Supply	
556.0	Sys. Contrl. & Load Dspatch	1,531
557.0	Other Exp./Misc. Purchased Power	1,209
	Total Other Power Supply	$ 2,740
	TOTAL OTHER PRODUCTION (1988$)	$ 5,122
	Escalation Amounts, 1988 to 1993	
	Labor	577
	Non-Labor	497
	Other	0
	Total	$ 1,075
	TOTAL OTHER PRODUCTION (1993$)	$ 6,197

TRANSMISSION EXPENSE

(Thousands Of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Operation	
560.0	Supervision and Engineering	$ 885
561.0	Load Dispatching	1,334
562.0	Station Expenses	397
563.0	Overhead Line Expenses	514
564.0	Underground Line Expenses	0
566.0	Misc. Transmission Expenses	1,557
567.0	Rents	497
	Total Operation	$ 5,184
	Maintenance	
568.0	Supervision and Engineering	147
569.0	Structures	0
570.0	Station Equipment	1,769
571.0	Overhead Lines	1,982
572.0	Underground Lines	7
573.0	Misc. Transmission Plant	8
	Total Maintenance	$ 3,913
	TOTAL TRANSMISSION (1988$)	$ 9,097
	Escalation Amounts, 1988 to 1993	
	Labor	1,245
	Non-Labor	620
	Other	0
	Total	$ 1,865
	TOTAL TRANSMISSION (1993$)	$ 10,962

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DISTRIBUTION EXPENSE

(Thousands Of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Operation	
580.0	Supervision and Engineering	$ 3,187
581.0	Load Dispatching	856
582.0	Station Expenses	2,260
583.0	Overhead Line Expenses	1,638
584.0	Underground Line Expenses	1,261
585.0	Street Lighting & Signal Sys.	217
586.0	Meter Expenses	3,230
587.0	Customer Installations	1,927
588.0	Misc. Distribution Expenses	4,926
589.0	Rents	113
	Total Operation	$ 19,615
	Maintenance	
590.0	Supervision and Engineering	324
591.0	Structures	41
592.0	Station Equipment	1,358
593.0	Overhead Services	8,486
594.0	Underground Lines	3,192
595.0	Line Transformers	536

Account No.	Description	Adopted
596.0	Street Lighting & Signal Sys.	242
597.0	Meters	908
598.0	Misc. Distribution Plant	31
	Total Maintenance	$ 15,118
	TOTAL DISTRIBUTION (1988$)	$ 34,733
	Escalation Amounts, 1988 to 1993	
	Labor	4,527
	Non-Labor	2,559
	Other	0
	Total	$ 7,086
	TOTAL DISTRIBUTION (1993$)	$ 41,819

CUSTOMER ACCOUNTS EXPENSE

(Thousands Of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
901.0	Supervision	$ 261
902.0	Meter Reading Expenses	4,714
903.0	Cust. Records and Collectibles n1	20,351
904.0	Uncollectible Accounts	2,555
905.0	Misc. Customer Accounts Exp.	81
	TOTAL CUSTOMER ACCTS. (1988$)	$ 27,962
	Total (Less Uncollectibles)	$ 25,407
	Escalation Amounts, 1988 to 1993	
	Labor	3,228
	Non-Labor	1,509
	Other	0
	Total	$ 4,737
	TOTAL CUSTOMER ACCTS. (1993$)	$ 32,699
	Total (Less Uncollectibles)	$ 30,144

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n1 Including costs for Energy Service of $ 1,620.

MARKETING EXPENSE

(Thousands Of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Cust. Serv. & Info. (DSM)	
907.0	Supervision & Clerical	$ 1,099
908.0	Customer Assistance Expense	33,001
909.0	Informational & Instruct. Exp.	0
910.0	Misc. Cust. Serv. & Info.	2,704
916.0	Misc. Expenses	360
	Electric Vehicle	
912.0	Demonstration & Service Exp.	0
	TOTAL MARKETING (1988$)	$ 37,164
	Escalation Amounts, 1988 to 1993	
	Labor	896
	Non-Labor	6,080

Account No.	Description	Adopted
	Other	0
	Total	$ 6,976
	TOTAL MARKETING (1993$)	$ 44,140

ADMINISTRATIVE & GENERAL EXPENSES

(Thousands Of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Operation	
920.0	Administrative & Gen. Salaries	$ 17,780
921.0	Office Supplies and Expenses	9,627
922.0	Admin. & Gen. Transfer Credit	(11,553)
923.0	Outside Services Employed	4,194
924.0	Property Insurance	3,797
925.0	Injuries and Damages	8,590
926.0	Pensions and Benefits-Total	25,865
927.0	Franchise Requirements	18,000
928.0	Regulatory Commission Expenses	4,623
929.0	Duplicate Charges	(1,412)
930.0	Misc. General Expenses	10,481
931.0	Rents	2,263
	Total Operation	$ 92,255
	Maintenance	
935.0	Maintenance of General Plant	2,383
	Total Maintenance	$ 2,383
	TOTAL ADMIN. & GEN. (1988$)	$ 94,638
	Total (Less Franchise Req.)	$ 76,638
	Escalation Amounts, 1988 to 1993	
	Labor	4,321
	Non-Labor	3,808
	Other	0
	Total	$ 8,128
	TOTAL ADMIN. & GEN. (1993$)	$ 102,766
	Total (Less Franchise Req.)	$ 84,766

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OPER. & MAINT. EXPENSE SUMMARY

(Thousands of 1988 Dollars)

Description	Adopted
Total Labor	
Production	$ 51,740
Transmission	5,727
Distribution	20,825
Customer Accounts	14,847
Marketing	4,123
Administrative and General	19,875
Other Adjustment	(1,294)
Total Labor (1988$)	$ 115,843
Total Non-Labor	
Production	39,721
Transmission	3,370

Description	Adopted
Distribution	13,908
Customer Accounts	8,202
Marketing	33,041
Administrative and General	20,695
Other Adjustment	0
Total Non-Labor (1988$)	$ 118,937
Total Other	
Production	14,778
Transmission	0
Distribution	0
Customer Accounts	4,913
Marketing	0
Administrative and General	54,068
Other Adjustment	0
Total Other (1988$)	$ 73,760
TOTAL O&M (1988$)	$ 308,539

OPER. & MAINT. EXPENSE SUMMARY

(Thousands of 1993 Dollars)

Description	Adopted
Total Labor	
Production	$ 60,792
Transmission	6,972
Distribution	25,352
Customer Accounts	18,075
Marketing	5,019
Administrative and General	24,196
Other Adjustment	(1,575)
Total Labor (1993$)	$ 138,829
Total Non-Labor	
Production	46,401
Transmission	3,990
Distribution	16,467
Customer Accounts	9,711
Marketing	39,121
Administrative and General	24,502
Other Adjustment	0
Total Non-Labor (1993$)	$ 140,193
Total Other	
Production	14,778
Transmission	0
Distribution	0
Customer Accounts	4,913
Marketing	0
Administrative and General	54,068
Other Adjustment	0
Total Other (1993$)	$ 73,760
TOTAL O&M (1993$)	$ 352,782
Escalation Amounts, 1988 to 1993	
Labor	$ 22,987
Non-Labor	21,256
Other	0
Total	$ 44,243

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TAXES OTHER THAN ON INCOME

(Thousands of 1993 Dollars)

Description	Adopted
Ad Valorem Taxes	
California	$ 35,195
Total Ad Valorem Taxes	35,195
Payroll & Misc. Taxes	
Federal Insurance Contrib. Act (FICA)	3,250
Medicare	795
Federal Unemployment Insurance (FUI)	77
State Unemployment Insurance (SUI)	19
Miscellaneous Taxes	550
Subtotal	$ 4,691
Labor Escalation Adjustment	819
Total Payroll & Misc.	$ 5,510
TOTAL TAXES OTHER THAN ON INCOME (1993$)	$ 40,705

INCOME TAX ADJUSTMENTS

(Thousands of 1993 Dollars)

Description	Adopted
California Income Tax Adjustments	
Nuclear Decommissioning	$ 18,735
Excess Salvage	(328)
State Tax Depreciation	148,968
Book Depreciation	(188,102)
Cost of Removal	4,401
Prop. Tax: Book vs. Lien Date	884
20% Business Meals	(138)
Percent. Repair Allow	12,756
Reinstallation Costs	(301)
PBOP Contributions to Grant Trust	(727)
TOTAL CCFT ADJUSTMENTS	($ 3,852)
Federal Income Tax Adjustments	
Nuclear Decommissioning	$ 18,735
Excess Salvage	(328)
Federal Tax Depreciation	109,090
Book Depreciation	(188,102)
Cost of Removal	2,530
Prop. Tax: Book vs. Lien Date	884
20% Business Meals	(138)
Preferred Dividend Credit	470
Percent. Repair Allow	6,937
Reinstallation Costs	(301)
PBOP Contributions to Grant Trust	(727)
TOTAL FIT ADJUSTMENTS	($ 50,950)
Interest Charges	
Rate Base	$ 2,393,984
Unamortized ITC	(93,886)
Adjusted Rate Base	$ 2,300,098
Wtd. Cost of Long Term Debt	3.660%
State Allocation	$ 84,184

Description	Adopted
Federal Allocation	$ 87,620

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TAXES ON INCOME - ADOPTED RATES

(Thousands of 1993 Dollars)

Description	Adopted
California Corporation Franchise Tax	
Operating Revenues	$ 949,074
Operating Expenses (Incl. Depr.)	546,252
Taxes Other Than on Income	40,705
Interest Charges	84,184
State Income Tax Adjustments	(3,852)
California Taxable Income	$ 281,786
CCFT Rate	9.3%
TOTAL CCFT	$ 26,206
Federal Income Tax	
Operating Revenues	$ 949,074
Operating Expenses	546,252
Taxes Other Than on Income	40,705
Interest Charges	87,620
CCFT - Prior Year	25,540
Federal Income Tax Adjustments	(50,950)
Federal Taxable Income	$ 299,908
FIT Tax Rate	34%
Federal Income Tax	$ 101,969
Amortization of ITC	(4,019)
Total Federal Income Tax	$ 97,950
TOTAL TAXES ON INCOME	$ 124,156

DEPRECIATION & AMORTIZATION EXPENSE

(Thousands of 1993 Dollars)

Description	Adopted
Depreciation Expense	
Steam Production	$ 19,312
Nuclear Prod. - SONGS 1	7,505
Nuclear Prod. - SONGS 2, 3	36,499
Nuclear Decommissioning	22,038
Other Production	2,365
Total Production	$ 87,719
Transmission - SWPL	7,188
Transmission - Other	9,838
Distribution & General	78,775
Total Depr. Exp. for PIS	$ 183,520
Prorata Depreciation Expense	
Based on Depr. of Common Plant	4,582
Total Depreciation Expense	$ 188,102
Amortization Expense	
Limited Term Investments	0
Land Rights	1,372
Amort. of Abandoned Projects	1,505
Software	2,475
Amort. of Elect. Acq. Adj.	16

Description	Adopted
Total Amortization Expense	$ 5,368
TOTAL DEPRECIATION & AMORTIZATION	$ 193,470

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DEPRECIATION RESERVE

(Thousands of 1993 Dollars)

Description	Adopted
Depreciation Reserve - Wtd. Avg.	
Steam Production	$ 245,788
Nuclear Prod. - SONGS 1	72,661
Nuclear Prod. - SONGS 2, 3	331,228
Nuclear Decommissioning	0
Other Production	37,899
Total Production	$ 687,576
Transmission - SWPL	63,705
Transmission - Other	133,473
Distribution & General	651,423
Total Depr. Res. for PIS	$ 1,536,177
Prorata Depreciation Expense	
Based on Depr. of Common Plant	23,316
	$ 1,559,493
Amortization Reserve	
Limited Term Investments	203
Land Rights	14,135
Software	6,681
Amort. of Elect. Acq. Adj.	173
Total EOY Amort. Reserve	$ 21,192
Total EOY Dep. & Amort. Reserve	$ 1,580,685
Total Weighted Depr. Reserve	
for Rate Base	$ 1,480,154
Total Weighted Amort. Reserve	
for Rate Base	$ 13,733

RATE BASE

(Thousands of 1993 Dollars)

Description	Adopted
Fixed Capital - Weighted Average	
Plant in Service - 1993 BOY	$ 4,029,878
PHFU	0
Total Fixed Capital - 1993 BOY	4,029,878
1993 Plant Additions - Wtd. Avg.	114,503
Total Fixed Capital - Wtd. Avg.	$ 4,144,381
Customer Advance for Construction	($ 28,549)
Working Capital	
Materials & Supplies	42,507
Working Cash	7,916
Total Working Capital	$ 50,423
Tot. Before Deduction for Reserves	$ 4,166,255
Deductions for Reserves	
Depreciation	(1,480,154)
Deferred Income Taxes	(278,384)
Amortization & Other	(13,733)

Description	Adopted
Total Deduction for Reserves	($ 1,772,271)
WTD. AVG. DEPRECIATED RATE BASE	$ 2,393,984

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DEVELOPMENT OF NET-TO-GROSS MULTIPLIER

Description	Rate	Amount Applied	Total
	(A)	(B)	(C = A*B)
Gross Operating Revenues			1.000000
Less: Uncollectibles	0.2740%		
Less: Franchise Fees	1.9300%		
	2.2040%	1.0000	0.022040
Subtotal			0.977960
Less: S.I.T.	9.3%		
Less: F.I.T.	34%		
	43.3%	0.97796	0.423457
Net Operating Revenues			0.554503
N-T-G Multiplier			1.803416
N-T-G Multiplier (FF&U Only)			1.022537
N-T-G Multiplier (Taxes Only)			1.763668

APPENDIX F

SAN DIEGO GAS & ELECTRIC COMPANY

GAS DEPARTMENT

Test Year 1993

RESULTS OF OPERATION

FRANCHISE FEES AND UNCOLLECTIBLES - ADOPTED RATES

(Thousands of 1993 Dollars)

Description	Adopted
Uncollectibles	
Adopted Base Rate Revenues - Retail	$ 161,520
Uncollectible Rate	0.2740%
Total Uncollectibles	$ 443
Franchise Requirements	
Adopted Base Rate Revenues - Retail	$ 161,520
Franchise Fee Rate	2.1800%
Total Franchise Fees	$ 3,521

SUPPLY EXPENSE

(Thousands Of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
807.0	Purchased Gas Expenses	$ 1,301
810.0	Compressor Station Fuel - Credit	(934)
812.0	Gas for Other Operations - Credit	(46)
	Total Gas Supply (1988 $)	$ 321
	Escalation Amounts, 1988 to 1993	
	Labor	223
	Non-Labor	50
	Other	0
	Total	$ 273
	TOTAL GAS SUPPLY (1993 $)	$ 594

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STORAGE EXPENSE

(Thousands of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Operation	
840.0	Oper. Supervision and Engineering	$ 143
841.0	Operation Labor & Expenses	56
	Total Operation	$ 199
	Maintenance	
843.0	Maintenance	30
	Total Maintenance	$ 30
	TOTAL GAS STORAGE (1988 $)	$ 229

Account No.	Description	Adopted
	Escalation Amounts, 1988 to 1993	
	Labor	17
	Non-Labor	33
	Other	0
	Total	$ 50
	TOTAL GAS STORAGE (1993 $)	$ 279

TRANSMISSION EXPENSE

(Thousands Of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Operation	
850.0	Oper. Supervision and Engineering	$ 596
851.0	System Control & Load Dispatch	332
852.0	Communication Systems Expenses	20
853.0	Compressor Station Labor & Exp	1,062
854.0	Gas for Compressor Station Fuel	934
855.0	Other Fuel & Power for Compr. Sta.	96
856.0	Mains Expenses	435
857.0	Measuring & Regulating Sta. Exp.	106
859.0	Other Expenses	143
860.0	Rents	58
	Total Operation	$ 3,782
	Maintenance	
861.0	Maint. Supervision and Engineering	303
862.0	Maint. of Structures & Improvements	4
863.0	Maintenance of Mains	4
864.0	Maint. of Compressor Station Equip.	887
865.0	Maint. of Meas. & Reg. Sta. Equip.	64
867.0	Maintenance of Other Equipment	0
	Total Maintenance	$ 1,262
	TOTAL TRANSMISSION (1988 $)	$ 5,044
	Escalation Amounts, 1988 to 1993	
	Labor	561
	Non-Labor	280
	Other	0
	Total	$ 842
	TOTAL TRANSMISSION (1993 $)	$ 5,886

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DISTRIBUTION EXPENSE

(Thousands Of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Operation	
870.0	Oper. Supervision and Engineering	$ 2,526
871.0	Distribution Load Dispatching	275
874.0	Mains & Services Expenses	1,550
875.0	Meas. & Reg. Sta. Exp. - General	160
878.0	Meter & House Regulation Expenses	2,865
879.0	Customer Installation Expenses	5,631

Account No.	Description	Adopted
880.0	Other Expenses	1,370
881.0	Rents	84
	Total Operation	$ 14,461
	Maintenance	
885.0	Maint. Supervision and Engineering	277
886.0	Maint. of Structures & Improvements	0
887.0	Maintenance of Mains	1,433
889.0	Maint. of Meas. & Reg. Sta. Equip.	123
892.0	Maint. of Services	594
893.0	Maint. of Meters & House Regulation	599
894.0	Maintenance of Other Equipment	0
	Total Maintenance	$ 3,026
	TOTAL DISTRIBUTION (1988 $)	$ 17,487
	Escalation Amounts, 1988 to 1993	
	Labor	2,933
	Non-Labor	730
	Other	0
	Total	$ 3,664
	TOTAL DISTRIBUTION (1993 $)	$ 21,151

CUSTOMER ACCOUNTS EXPENSE

(Thousands of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
901.0	Supervision	$ 142
902.0	Meter Reading Expenses	2,567
903.0	Cust. Records and Collectibles n1	10,585
904.0	Uncollectible Accounts	443
905.0	Misc. Customer Accounts Exp.	44
	TOTAL CUSTOMER ACCTS. (1988 $)	$ 13,781
	Total (Less Uncollectibles)	$ 13,338
	Escalation Amounts, 1988 to 1993	
	Labor	1,669
	Non-Labor	803
	Other	0
	Total	$ 2,471
	TOTAL CUSTOMER ACCTS. (1993 $)	$ 16,252
	Total (Less Uncollectibles)	$ 15,809

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n1 Including costs for Energy Service of $ 380.

MARKETING EXPENSE

(Thousands Of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Cust. Serv. & Info. (DSM)	
907.0	Supervision & Clerical	$ 233
908.0	Customer Assistance Expense	7,248
909.0	Informational & Instruct. Exp.	0

Account No.	Description	Adopted
910.0	Misc. Cust. Serv. & Info.	574
916.0	Misc. Expenses	77
	TOTAL MARKETING (1988 $)	$ 8,132
	Escalation Amounts, 1988 to 1993	
	Labor	276
	Non-Labor	1,263
	Other	0
	Total	$ 1,538
	TOTAL MARKETING (1993 $)	$ 9,670

ADMINISTRATIVE & GENERAL EXPENSES

(Thousands of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Operation	
920.0	Administrative & Gen. Salaries	$ 6,013
921.0	Office Supplies and Expenses	3,270
922.0	Admin. & Gen. Transfer Credit	(4,223)
923.0	Outside Services Employed	1,417
924.0	Property Insurance	174
925.0	Injuries and Damages	2,422
926.0	Pensions and Benefits-Total	10,384
927.0	Franchise Requirements	3,521
928.0	Regulatory Commission Expenses	1,587
930.0	Misc. General Expenses	2,956
931.0	Rents	764
	Total Operation	$ 28,285
	Maintenance	
935.0	Maintenance of General Plant	805
	Total Maintenance	$ 805
	TOTAL ADMIN. & GEN. (1988 $)	29,090
	Total (Less Franchise Req.)	$ 25,569
	Escalation Amounts, 1988 to 1993	
	Labor	1,474
	Non-Labor	1,153
	Other	0
	Total	$ 2,627
	TOTAL ADMIN. & GEN. (1993 $)	$ 31,717
	Total (Less Franchise Req.)	$ 28,196

[*254]

OPER. & MAINT. EXPENSE SUMMARY

(Thousands of 1988 Dollars)

Description	Adopted
Total Labor	
Supply	1,029
Storage	77
Transmission	2,586
Distribution	13,517
Customer Accounts	7,689
Marketing	1,270

Description	Adopted
Administrative and General	6,794
Other Adjustment	(488)
Total Labor (1988 $)	$ 32,474
Total Non-Labor	
Supply	272
Storage	152
Transmission	1,524
Distribution	3,970
Customer Accounts	4,364
Marketing	6,862
Administrative and General	6,264
Other Adjustment	0
Total Non-Labor (1988 $)	$ 23,408
Total Other	
Supply	($ 980)
Storage	0
Transmission	934
Distribution	0
Customer Accounts	1,728
Marketing	0
Administrative and General	16,032
Other Adjustment	0
Total Other (1988 $)	$ 17,714
TOTAL O&M (1988 $)	$ 73,596

(Thousands of 1993 Dollars)

Description	Adopted
Total Labor	
Supply	$ 1,252
Storage	94
Transmission	3,147
Distribution	16,450
Customer Accounts	9,358
Marketing	1,546
Administrative and General	8,268
Other Adjustment	(594)
Total Labor (1993 $)	$ 39,521
Total Non-Labor	
Supply	$ 322
Storage	185
Transmission	1,804
Distribution	4,700
Customer Accounts	5,167
Marketing	8,124
Administrative and General	7,417
Other Adjustment	0
Total Non-Labor (1993 $)	$ 27,720
Total Other	
Supply	($ 980)
Storage	0

Description	Adopted
Transmission	934
Distribution	1,728
Customer Accounts	0
Marketing	16,032
Administrative and General	0
Other Adjustment	$ 17,714
Total Other (1993 $)	$ 84,954
Escalation Amounts, 1988 to 1993	
Labor	$ 7,047
Non-Labor	4,312
Other	0
Total	$ 11,359

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TAXES OTHER THAN ON INCOME

(Thousands of 1993 Dollars)

Description	Adopted
Ad Valorem Taxes	
California	$ 5,240
Total Ad Valorem Taxes	5,240
Payroll & Misc. Taxes	
Federal Insurance Contrib. Act (FICA)	1,183
Medicare	290
Federal Unemployment Insurance (FUI)	28
State Unemployment Insurance (SUI)	7
Miscellaneous Taxes	3
Subtotal	$ 1,511
Labor Escalation Adjustment	298
Total Payroll & Misc.	$ 1,809
TOTAL TAXES OTHER THAN ON INCOME (1993 $)	$ 7,049

INCOME TAX ADJUSTMENTS

(Thousands of 1993 Dollars)

Description	Adopted
California Income Tax Adjustments	
Excess Salvage	($ 82)
State Tax Depreciation	24,646
Book Depreciation	(28,021)
Cost of Removal	587
Prop. Tax: Book vs. Lien Date	180
20% Business Meals	(35)
Percent. Repair Allow	2,189
PBOP Contributions to Grant Trust	(150)
TOTAL CCFT ADJUSTMENTS	($ 686)
Federal Income Tax Adjustments	
Excess Salvage	($ 82)
Federal Tax Depreciation	19,868
Book Depreciation	(28,021)
Cost of Removal	338
Prop. Tax: Book vs. Lien Date	180
20% Business Meals	(35)

Description	Adopted
Preferred Dividend Credit	56
Percent. Repair Allow	193
PBOP Contributions to Grant Trust	(150)
TOTAL FIT ADJUSTMENTS	($ 7,653)
Interest Charges	
Rate Base	$ 365,601
Unamortized ITC	(7,998)
Adjusted Rate Base	$ 357,603
Wtd. Cost of Long Term Debt	3.66%
State Allocation	$ 13,088
Federal Allocation	$ 13,381

[*256]

TAXES ON INCOME - ADOPTED RATES

(Thousands of 1993 Dollars)

Description	Adopted
California Corporation Franchise Tax	
Operating Revenues	$ 176,225
Operating Expenses	114,093
Taxes Other Than on Income	7,049
Interest Charges	13,088
State Income Tax Adjustments	(686)
California Taxable Income	$ 42,680
CCFT Rate	9.3%
TOTAL CCFT	$ 3,969
Federal Income Tax	
Operating Revenues	$ 176,225
Operating Expenses	114,093
Taxes Other Than on Income	7,049
Interest Charges	13,381
CCFT - Prior Year	4,797
Federal Income Tax Adjustments	(7,653)
Federal Taxable Income	$ 44,558
FIT Tax Rate	34%
Federal Income Tax	$ 15,150
Amortization of ITC	(377)
Total Federal Income Tax	$ 14,773
TOTAL TAXES ON INCOME	$ 18,742

DEPRECIATION & AMORTIZATION EXPENSE

(Thousands of 1993 Dollars)

Description	Adopted
Depreciation Expense	
Storage Plant	$ 86
Transmission Plant	2,868
Distribution & General Plant	23,408
Total Depr. Exp. for PIS	$ 26,362
Prorata Depreciation Expense	
Based on Depr. of Common Plant	1,659
Total Depreciation Expense	$ 28,021

Description	Adopted
Amortization Expense	
Limited Term Investments	0
Land Rights	171
Amort. of Abandoned Projects	0
Software	947
Total Amortization Expense	$ 1,118
TOTAL DEPRECIATION & AMORTIZATION	$ 29,139

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DEPRECIATION RESERVE

(Thousands of 1993 Dollars)

Description	Adopted
Depreciation Reserve - Wtd. Avg.	
Storage Plan	$ 1,513
Transmission Plant	29,038
Distribution & General Plant	263,809
Total Depr. Res. for PIS	$ 294,360
Prorata Depreciation Expense	
Based on Depr. of Common Plant	8,410
Total Depreciation Expense	$ 302,770
Amortization Reserve	
Limited Term Investments	89
Land Rights	2,278
Software	2,481
Total EOY Amort. Reserve	$ 4,848
Total EOY Dep. & Amort. Reserve	$ 307,618
Total Weighted Depr. Reserve	
for Rate Base	$ 289,081
Total Weighted Amort. Reserve	
for Rate Base	$ 3,912

RATE BASE

(Thousands of 1993 Dollars)

Description	Adopted
Fixed Capital - Weighted Average	
Plant in Service - 1993 BOY	$ 663,182
PHFU	0
Total Fixed Capital - 1993 BOY	663,182
1993 Plant Additions - Wtd. Avg.	21,282
Total Fixed Capital - Wtd. Avg.	$ 684,464
Customer Advance for Construction	($ 14,085)
Working Capital	
Fuel in Storage	172
Materials & Supplies	2755
Working Cash	3,365
Total Working Capital	$ 6,292
Tot. Before Deduction for Reserves	$ 676,671
Deductions for Reserves	

Description	Adopted
Depreciation	(289,081)
Deferred Income Taxes	(18,077)
Amortization & Other	(3,912)
Total Deduction for Reserves	($ 311,070)
WTD. AVG. DEPRECIATED RATE BASE	$ 365,601

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DEVELOPMENT OF NET-TO-GROSS MULTIPLIER

Description	Rate (A)	Amount Applied (B)	Total (C=A*B)
Gross Operating Revenues			1.000000
Less: Uncollectibles	0.2740%		
Less: Franchise Fees	2.1800%		
	2.4540%	1.0000	0.024540
Subtotal			0.975460
Less: S.I.T.	9.3%		
Less: F.I.T.	34%		
	43.3%	0.97546	0.422374
Net Operating Revenues			0.553086
N-T-G Multiplier			1.808038
N-T-G Multiplier (FF&U Only)			1.025157
N-T-G Multiplier (Taxes Only)			1.763668

APPENDIX G

SAN DIEGO GAS & ELECTRIC COMPANY

STEAM DEPARTMENT

Test Year 1993

FRANCHISE FEES AND UNCOLLECTIBLES - ADOPTED RATES

(Thousands of 1993 Dollars)

Description	Adopted
Uncollectibles	
Adopted Base Rate Revenues - Retail	$ 1,608
Uncollectible Rate	0.0000%
Total Uncollectibles	$ 0
Franchise Requirements	
Adopted Base Rate Revenues - Retail	$ 1,608
Franchise Fee Rate	2.1000%
Total Franchise Fees	$ 34

PRODUCTION EXPENSE

(Thousands Of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Operation	
601.0	Fuel - Diesel, Gas, & Handling	0
602.0	Purchased Gas Expenses	$ 352
	Total Operation	$ 352
	Maintenance	
612.0	Maint. of Steam Heat Equipment	243
	Total Maintenance	$ 243
	Total Steam Production (1988 $)	$ 595
	Escalation Amounts, 1988 to 1993	
	Labor	71
	Non-Labor	49
	Other	0
	Total	$ 120
	TOTAL STEAM PRODUCTION (1993 $)	$ 715

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DISTRIBUTION EXPENSE

(Thousands Of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Operation	
620.0	Oper. Supervision and Engineering	$ 12
624.0	Mains & Services Expenses	1
625.0	Meter & Regulator Expenses	0
627.0	Customer Installation Expenses	1
628.0	Other Expenses	0

Account No.	Description	Adopted
	Total Operation	$ 14
	Maintenance	
634.0	Maintenance of Mains	38
635.0	Maintenance of Services	5
636.0	Maintenance of Meters & Regulators	0
637.0	Maintenance of Other Equipment	6
	Total Maintenance	$ 49
	TOTAL DISTRIBUTION (1988 $)	$ 63
	Escalation Amounts, 1988 to 1993	
	Labor	10
	Non-Labor	3
	Other	0
	Total	$ 13
	TOTAL DISTRIBUTION (1993 $)	$ 76

CUSTOMER ACCOUNTS EXPENSE

(Thousands Of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
901.0	Supervision	$ 0
902.0	Meter Reading Expenses	1
903.0	Cust. Records and Collectibles	3
904.0	Uncollectible Accounts	0
905.0	Misc. Customer Accounts Exp.	0
	TOTAL CUSTOMER ACCTS. (1988 $)	$ 4
	Total (Less Uncollectibles)	$ 4
	Escalation Amounts, 1988 to 1993	
	Labor	1
	Non-Labor	0
	Other	0
	Total	$ 1
	TOTAL CUSTOMER ACCTS. (1993 $)	$ 5
	Total (Less Uncollectibles)	$ 5

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ADMINISTRATIVE & GENERAL EXPENSES

(Thousands of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Operation	
920.0	Administrative & Gen. Salaries	$ 60
921.0	Office Supplies and Expenses	33
922.0	Admin. & Gen. Transfer Credit	(39)
923.0	Outside Services Employed	14
924.0	Property Insurance	28
925.0	Injuries and Damages	84
926.0	Pensions and Benefits-Total	96
927.0	Franchise Requirements	34
928.0	Regulatory Commission Expenses	10
930.0	Misc. General Expenses	17
931.0	Rents	7

Account No.	Description	Adopted
	Total Operation	$ 344
	Maintenance	
935.0	Maintenance of General Plant	8
	Total Maintenance	$ 8
	TOTAL ADMIN. & GEN. (1988 $)	352
	Total (Less Franchise Req.)	$ 318
	Escalation Amounts, 1988 to 1993	
	Labor	15
	Non-Labor	11
	Other	0
	Total	$ 25
	TOTAL ADMIN. & GEN. (1993 $)	$ 377
	Total (Less Franchise Req.)	$ 343

OPER. & MAINT. EXPENSE SUMMARY

(Thousands of 1988 Dollars)

Description	Adopted
Total Labor	
Production	$ 328
Distribution	47
Customer Accounts	3
Administrative and General	69
Other Adjustments	(11)
Total Labor (1988 $)	$ 436
Total Non-Labor	
Production	$ 267
Distribution	16
Customer Accounts	1
Administrative and General	58
Other Adjustment	0
Total Non-Labor (1988 $)	$ 342
Total Other	
Production	$ 0
Distribution	0
Customer Accounts	0
Administrative and General	226
Other Adjustment	0
Total Other (1988 $)	$ 226
TOTAL O&M (1988 $)	$ 1,003

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OPER. & MAINT. EXPENSE SUMMARY

(Thousands of 1993 Dollars)

Description	Adopted
Total Labor	
Production	$ 399
Distribution	57
Customer Accounts	4
Administrative and General	83
Other Adjustment	(13)
Total Labor (1993 $)	$ 530

Description	Adopted
Total Non-Labor	
Production	$ 316
Distribution	19
Customer Accounts	1
Administrative and General	68
Other Adjustment	0
Total Non-Labor (1993 $)	$ 404
Total Other	
Production	$ 0
Distribution	0
Customer Accounts	0
Administrative and General	226
Other Adjustment	0
Total Other (1993 $)	$ 226
TOTAL O&M (1993 $)	$ 1,160
Escalation Amounts, 1988 to 1993	
Labor	$ 95
Non-Labor	63
Other	0
Total	$ 157

TAXES OTHER THAN ON INCOME

(Thousands of 1993 Dollars)

Description	Adopted
Ad Valorem Taxes	
California	$ 13
Total Ad Valorem Taxes	13
Payroll & Misc. Taxes	
Federal Insurance Contrib. Act (FICA)	25
Medicare	6
Federal Unemployment Insurance (FUI)	1
State Unemployment Insurance (SUI)	0
Miscellaneous Taxes	0
Subtotal	$ 32
Labor Escalation Adjustment	6
Total Payroll & Misc.	$ 38
TOTAL TAXES OTHER THAN ON INCOME (1993 $)	$ 51

INCOME TAX ADJUSTMENTS

(Thousands of 1993 Dollars)

Description	Adopted
California Income Tax Adjustments	
State Tax Depreciation	$ 121
Book Depreciation	(251)
Cost of Removal	12
Prop. Tax: Book vs. Lien Date	(1)
TOTAL CCFT ADJUSTMENTS	($ 119)
Federal Income Tax Adjustments	
Federal Tax Depreciation	$ 194
Book Depreciation	(251)
Cost of Removal	7
Prop. Tax: Book vs. Lien Date	(1)
TOTAL FIT ADJUSTMENTS	($ 51)

Description	Adopted
Interest Charges	
Rate Base	$ 625
Unamortized ITC	0
Adjusted Rate Base	625
Wtd. Cost of Long Term Debt	3.66%
State Allocation	$ 23
Federal Allocation	$ 23

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TAXES ON INCOME - ADOPTED RATES

(Thousands of 1993 Dollars)

Description	Adopted
California Corporation Franchise Tax	
Operating Revenues	$ 1,608
Operating Expenses	1,411
Taxes Other Than on Income	51
Interest Charges	23
State Income Tax Adjustments	(119)
California Taxable Income	$ 242
CCFT Rate	9.3%
TOTAL CCFT	$ 22
Federal Income Tax	
Operating Revenues	$ 1,608
Operating Expenses	1,411
Taxes Other Than on Income	51
Interest Charges	23
CCFT - Prior Year	(6)
Federal Income Tax Adjustments	(51)
Federal Taxable Income	$ 180
FIT Tax Rate	34%
Federal Income Tax	$ 61
Amortization of ITC	0
Total Federal Income Tax	$ 61
TOTAL TAXES ON INCOME	$ 84

DEPRECIATION & AMORTIZATION EXPENSE

(Thousands of 1993 Dollars)

Description	Adopted
Depreciation Expense	
Steam Plant	$ 239
Total Depr. Exp. for PIS	$ 239
Prorata Depreciation Expense	
Based on Depr. of Common Plant	12
Total Depreciation Expense	$ 251
Amortization Expense	
Limited Term Investments	0
Total Amortization Expense	$ 0
TOTAL DEPRECIATION & AMORTIZATION	$ 251

DEPRECIATION RESERVE

(Thousands of 1993 Dollars)

Description	Adopted
Depreciation Reserve - Wtd. Avg.	
Steam Plant	$ 5,673
Total Depr. Res. for PIS	$ 5,673
Prorata Depreciation Expense	
Based on Depr. of Common Plant	60
Total Depreciation Expense	$ 5,733
Amortization Reserve	
Limited Term Investments	4
Total EOY Amort. Reserve	$ 4
Total EOY Dep. & Amort. Reserve	$ 5,737
Total Weighted Depr. Reserve	
for Rate Base	$ 5,614
Total Weighted Amort. Reserve	
for Rate Base	$ 4

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RATE BASE

(Thousands of 1993 Dollars)

Description	Adopted
Fixed Capital - Weighted Average	
Plant in Service - 1993 BOY	$ 6,140
PHFU	0
Total Fixed Capital - 1993 BOY	6,140
1993 Plant Additions - Wtd. Avg.	9
Total Fixed Capital - Wtd. Avg.	$ 6,149
Customer Advance for Construction	$ 0
Working Capital	
Materials & Supplies	15
Working Cash	79
Total Working Capital	$ 94
Tot. Before Deduction for Reserves	$ 6,243
Deductions for Reserves	
Depreciation	(5,614)
Deferred Income Taxes	0
Amortization & Other	(4)
Total Deduction for Reserves	($ 5,618)
WTD. AVG. DEPRECIATED RATE BASE	$ 625

DEVELOPMENT OF NET-TO-GROSS MULTIPLIER

Description	Rate	Amount Applied	Total
	(A)	(B)	(C=A*B)
Gross Operating Revenues			1.000000
Less: Uncollectibles	0.0000%		
Less: Franchise Fees	2.1000%		
	2.1000%	1.0000	0.021000
Subtotal			0.979000
Less: S.I.T.	9.3%		
Less: F.I.T.	34%		
	43.3%	0.97900	0.423907
Net Operating Revenues			0.555093
N-T-G Multiplier			1.801500
N-T-G Multiplier (FF&U Only)			1.021450

Description	Rate	Amount Applied	Total
N-T-G Multiplier (Taxes Only)			1.763668

APPENDIX H

SAN DIEGO GAS & ELECTRIC COMPANY

ELECTRIC DEPARTMENT

ATTRITION BASE [*264] RATE REVENUE REQUIREMENT ESTIMATES

(Thousands of Dollars)

Description	GRC Adopted 1993 (a)	Incremt. Attrition 1994 (b)
Operating Revenues		
Base Rate Revenues - Retail	$ 932,642	$ 22,488
Miscellaneous	15,057	0
Non-Jurisdictional	1,375	0
Total Operating Revenues	$ 949,074	$ 22,488
Operating Expenses		
Production	121,970	(5,987)
Transmission	10,962	404
Distribution	41,819	1,554
Customer Accounts	30,144	1,021
Uncollectibles	2,555	62
Demand-Side-Management	44,140	1,830
Marketing (Non-DSM)	0	0
Administrative & General	84,766	1,856
Franchise Requirements	18,000	434
Other Adjustment	(1,575)	(53)
Subtotal	$ 352,782	$ 1,121
Depreciation	193,470	9,187
Taxes Other Than On Income	40,705	1,909
Taxes On Income	124,156	4,502
Total Operating Expenses	$ 711,112	$ 16,719
Net Operating Income	$ 237,962	$ 5,770
Rate Base	$ 2,393,984	$ 58,046
Rate of Return	9.94%	9.94%
DSM 1990 & 1991 Rewards n1	$ 3,603	$ 767
DSM Balancing Account Amort. n2	$ 3,395	$ 0
Total Base Rate Rev.	$ 956,072	$ 23,255

Description	Attrition 1994 (c)	Incremt. Attrition 1995 (d)	Attrition 1995 (e)
Operating Revenues			
Base Rate Revenues - Retail	$ 955,131	$ 45,908	$ 1,001,039
Miscellaneous	15,057	0	15,057
Non-Jurisdictional	1,375	0	1,375
Total Operating Revenues	$ 971,563	$ 45,908	$ 1,017,471
Operating Expenses			
Production	115,983	14,204	130,187
Transmission	11,366	447	11,813
Distribution	43,373	1,721	45,093
Customer Accounts	31,165	1,127	32,292
Uncollectibles	2,617	126	2,743
Demand-Side-Management	45,970	2,102	48,072
Marketing (Non-DSM)	0	0	0
Administrative & General	86,622	2,074	88,696
Franchise Requirements	18,434	886	19,320
Other Adjustment	(1,628)	(57)	(1,685)
Subtotal	$ 353,902	$ 22,629	$ 376,531
Depreciation	202,657	9,829	212,486
Taxes Other Than On Income	42,614	2,152	44,766
Taxes On Income	128,658	4,676	133,333
Total Operating Expenses	$ 727,831	$ 39,286	$ 767,117
Net Operating Income	$ 243,732	$ 6,622	$ 250,354
Rate Base	$ 2,452,030	$ 66,621	$ 2,518,651
Rate of Return	9.94%	9.94%	9.94%
DSM 1990 & 1991 Rewards n1	$ 4,370	($ 716)	$ 3,654
DSM Balancing Account Amort. n2	$ 3,395	$ 0	$ 3,395
Total Base Rate Rev.	$ 979,327	$ 45,192	$ 1,024,519

[*265]

n1 As shown in Appendix B, Page 5 of 5.

n2 As shown in Appendix B, Page 5 of 5. The amortized amount for 1994 & 1995 should be updated in the attrition filings.

SUMMARY OF ATTRITION INCREMENTAL REVENUE REQUIREMENTS

(Thousands of Dollars)

Description	Incremt. Attrition 1994 (a)	Incremt. Attrition 1995 (b)
O&M Expenses		
Labor Escalation	$ 4,553	$ 4,889
Non-Labor Escalation	5,510	6,555
Nuclear Refueling Exp. (SONGS)	(9,438)	10,173
Subtotal	$ 625	$ 21,617
Franchise Fees & Uncollectibles	14	487
Total O&M Expenses	$ 639	$ 22,104
Capital Related		
Depreciation	$ 16,203	$ 17,335
Ad Valorem Tax	1,952	2,200
Income Taxes	(5,298)	(6,025)
Rate Base	8,511	9,769
Subtotal	$ 21,367	$ 23,279
Franchise Fees & Uncollectibles	482	525
Total Capital Related	$ 21,849	$ 23,803
Total Oper. Attr. Incr. Rev. Reqt.	$ 22,488	$ 45,908
DSM 1990 & 1991 Rewards n1	$ 767	($ 716)
DSM Balancing Account Amort. n2	$ 0	$ 0
Total Attr. Incr. Rev. Reqt.	$ 23,255	$ 45,192

n1 Including FF&U.

n2 Including FF&U. The amortized amounts for 1994 & 1995 should be updated in SDG&E's attrition filings.

ESCALATION RATES [*266] FOR ATTRITION YEARS

(Base Year 1993)

	Labor		Non-Labor	
Year	Rate	Index	Rate	Index
1. Adopted Escalation Rates for Test Year 1993 n1				
1988	--	100.0	--	100.0
1989	3.82%	103.8	4.76%	104.8
1990	3.94%	107.9	3.55%	108.5
1991	4.51%	112.8	3.31%	112.1

	Labor		Non-Labor	
Year	Rate	Index	Rate	Index
1992	4.33%	117.7	2.17%	114.5
1993	3.47%	121.7	3.43%	118.4
2. Estimated Escalation Rates for Attrition Years n2				
1993	--	100.0	--	100.0
1994	3.37%	103.4	4.25%	104.2
1995	3.48%	107.0	4.71%	109.2

n1 As shown in Appendix D, Page 1 of 1.

n2 As estimated in SDG&E's Updated Results of Opr. (Exh. 64, Page 14-15). Actual escalation rates for attrition year 1994 & 1995 should be updated in SDG&E's attrition filings.

ATTRITION INCREMENTAL O&M EXPENSES

(Thousands of Dollars)

Description	GRC Adopted 1993 (a)	Transfer of Other to Labor/ Non-Labor (b)
Operating Expenses		
Production n1		
Labor	$ 57,943	$ 0
Non-Labor	39,812	0
Other	14,778	0
Total Production	$ 112,532	$ 0
No. of Refueling Outages (SONGS) n2	2 (Unit 2 & 3)	
Refueling Outage for SONGS n1		
Labor	2,849	0
Non-Labor	6,589	0
Total Refueling Outage	$ 9,438	$ 0
Total Production		
Labor	60,792	0
Non-Labor	46,401	0
Other	14,778	0
Total Production	$ 121,970	$ 0

Description	GRC Adopted 1993 (a)	Transfer of Other to Labor/ Non-Labor (b)
Transmission		
Labor	6,972	0
Non-Labor	3,990	0
Other	0	0
Total Transmission	$ 10,962	$ 0
Distribution		
Labor	25,352	0
Non-Labor	16,467	0
Other	0	0
Total Distribution	$ 41,819	$ 0
Customer Accounts		
Labor	$ 18,075	$ 0
Non-Labor	9,711	0
Other (Less Uncoll.)	2,358	0
Total Customer Acct.	$ 30,144	$ 0
Marketing (DSM)		
Labor	5,019	0
Non-Labor	39,121	0
Other	0	0
Total Marketing	$ 44,140	$ 0
Administrative & General		
Labor	24,196	0
Non-Labor	24,502	0
Other (Less Franchise Fees)	36,069	0
Total A&G	$ 84,766	$ 0
Other Adjustment		
Labor	(1,575)	0
(Excl. Nuclear Refueling)		
Total Labor	135,981	0
Total Non-Labor	133,603	0
Total Other (Less FF&U)	53,204	0
Total O&M (Less FF&U)	$ 322,788	$ 0
Increment for Attrition		
(Incl. Nuclear Refueling)		
Total Labor	138,829	0
Total Non-Labor	140,193	0
Total Other (Less FF&U)	53,204	0

Description	GRC Adopted 1993 (a)	Transfer of Other to Labor/ Non-Labor (b)
Total O&M (Less FF&U)	$ 332,226	$ 0
Increment for Attrition		

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Description	Total for 1994 Attrition Purpose (c)	Attrition 1994 (d)	Attrition 1995 (e)
Operating Expenses			
Production n1			
Labor	$ 57,943	$ 59,866	$ 61,949
Non-Labor	39,812	41,339	43,287
Other	14,778	14,778	14,778
Total Production	$ 112,532	$ 115,983	$ 120,014
No. of Refueling Outages (SONGS) n2	2 (Unit 2 & 3)	0	2 (Unit 2 & 3)
Refueling Outage for SONGS n1			
Labor	2,849	0	3,045
Non-Labor	6,589	0	7,128
Total Refueling Outage	$ 9,438	$ 0	$ 10,173
Total Production			
Labor	60,792	59,866	64,994
Non-Labor	46,401	41,339	50,415
Other	14,778	14,778	14,778
Total Production	$ 121,970	$ 115,983	$ 130,187
Transmission			
Labor	6,972	7,207	7,458
Non-Labor	3,990	4,159	4,355
Other	0	0	0
Total Transmission	$ 10,962	$ 11,366	$ 11,813
Distribution			
Labor	25,352	26,206	27,118
Non-Labor	16,467	17,166	17,975
Other	0	0	0
Total Distribution	$ 41,819	$ 43,373	$ 45,093
Customer Accounts			
Labor	$ 18,075	$ 18,684	$ 19,334

Description	Total for 1994 Attrition Purpose (c)	Attrition 1994 (d)	Attrition 1995 (e)
Non-Labor	9,711	10,124	10,601
Other (Less Uncoll.)	2,358	2,358	2,358
Total Customer Acct.	$ 30,144	$ 31,165	$ 32,292
Marketing (DSM)			
Labor	5,019	5,188	5,369
Non-Labor	39,121	40,782	42,704
Other	0	0	0
Total Marketing	$ 44,140	$ 45,970	$ 48,072
Administrative & General			
Labor	24,196	25,011	25,881
Non-Labor	24,502	25,543	26,746
Other (Less Franchise Fees)	36,069	36,069	36,069
Total A&G	$ 84,766	$ 86,622	$ 88,696
Other Adjustment			
Labor	(1,575)	(1,628)	(1,685)
(Excl. Nuclear Refueling)			
Total Labor	135,981	140,534	145,423
Total Non-Labor	133,603	139,113	145,668
Total Other (Less FF&U)	53,204	53,204	53,204
Total O&M (Less FF&U)	$ 322,788	$ 332,851	$ 344,296
Increment for Attrition		$ 10,064	$ 11,444
(Incl. Nuclear Refueling)			
Total Labor	138,829	140,534	148,469
Total Non-Labor	140,193	139,113	152,796
Total Other (Less FF&U)	53,204	53,204	53,204
Total O&M (Less FF&U)	$ 332,226	$ 332,851	$ 354,469
Increment for Attrition		$ 625	$ 21,617

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n1 Excluding SONGS refueling outage costs.

SONGS O&M expenses for Attrition Year 1994 are escalated using SCE's escalation rates estimated in SCE's 1992 GRC decision (D.91-12-076, Appendix E, Page 3 of 10). SCE's escalation rates for 1995 are not available in its GRC decision. Therefore, SDG&E's escalation rates for 1995 are used.

n2 Based on SCE's updated refueling schedules in its 1993 attrition filing (A.L. 971-E).

INCOME TAX ADJUSTMENTS FOR ATTRITION YEARS

(Thousands of Dollars)

Description	GRC Adopted 1993 (a)	Incremt. Attrition 1994 (b)
California Income Tax Adjustments		
State Tax Depreciation	$ 148,968	$ 8,082
Book Depreciation	(188,102)	(9,187)
Other Adjustments	35,282	0
TOTAL CCFT ADJUSTMENTS	($ 3,852)	($ 1,105)
Federal Income Tax Adjustments		
Federal Tax Depreciation	109,090	5,918
Book Depreciation	(188,102)	(9,187)
Other Adjustments	28,062	0
TOTAL FIT ADJUSTMENTS	($ 50,950)	($ 3,269)
Interest Charges		
Rate Base	$ 2,393,984	58,046
Unamortized ITC	(93,886)	4,019
Adjusted Rate Base	$ 2,300,098	$ 62,065
Wtd. Cost of Long Term Debt	3.660%	3.660%
State Allocation	$ 84,184	$ 2,272
Federal Allocation	$ 87,620	$ 2,124

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Description	Attrition 1994 (c)	Incremt. Attrition 1995 (d)	Attrition 1995 (e)
California Income Tax Adjustments			
State Tax Depreciation	$ 157,050	$ 9,108	$ 166,158
Book Depreciation	(197,289)	(9,829)	(207,118)
Other Adjustments	35,282	0	35,282
TOTAL CCFT ADJUSTMENTS	($ 4,957)	($ 721)	($ 5,678)
Federal Income Tax Adjustments			
Federal Tax Depreciation	115,008	6,670	121,678
Book Depreciation	(197,289)	(9,829)	(207,118)

Description	Attrition 1994 (c)	Incremt. Attrition 1995 (d)	Attrition 1995 (e)
Other Adjustments	28,062	0	28,062
TOTAL FIT ADJUSTMENTS	($ 54,219)	($ 3,159)	($ 57,378)
Interest Charges			
Rate Base	$ 2,452,030	$ 66,621	$ 2,518,651
Unamortized ITC	(89,867)	4,019	(85,848)
Adjusted Rate Base	$ 2,362,163	$ 70,640	$ 2,432,803
Wtd. Cost of Long Term Debt	3.660%	3.660%	3.660%
State Allocation	$ 86,455	$ 2,585	$ 89,041
Federal Allocation	$ 89,744	$ 2,438	$ 92,183

TAXES ON INCOME FOR ATTRITION YEARS

(Thousands of Dollars)

Description	GRC Adopted 1993 (a)	Attrition 1994 (b)	Attrition 1995 (c)
Calif. Corporation Franchise Tax			
Operating Revenues	$ 949,074	$ 971,563	$ 1,017,471
Operating Expenses (Incl. Depr.)	546,252	556,559	589,017
Taxes Other Than on Income	40,705	42,614	44,766
Interest Charges	84,184	86,455	89,041
State Income Tax Adjustments	(3,852)	(4,957)	(5,678)
California Taxable Income	$ 281,786	$ 290,891	$ 300,325
CCFT Rate	9.3%	9.3%	9.3%
TOTAL CCFT	$ 26,206	$ 27,053	$ 27,930
Federal Income Tax			
Operating Revenues	$ 949,074	$ 971,563	$ 1,017,471
Operating Expenses	546,252	556,559	589,017
Taxes Other Than on Income	40,705	42,614	44,766
Interest Charges	87,620	89,744	92,183
CCFT - Prior Year	25,540	26,206	27,053
Federal Income Tax Adjustments	(50,950)	(54,219)	(57,378)
Federal Taxable Income	$ 299,908	$ 310,658	$ 321,830
FIT Tax Rate	34%	34%	34%

Description	GRC Adopted 1993 (a)	Attrition 1994 (b)	Attrition 1995 (c)
Federal Income Tax	$ 101,969	$ 105,624	$ 109,422
Amortization of ITC	(4,019)	(4,019)	(4,019)
Total Federal Income Tax	$ 97,950	$ 101,605	$ 105,403
TOTAL TAXES ON INCOME	$ 124,156	$ 128,658	$ 133,333

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RATE BASE FOR ATTRITION YEARS

(Thousands of Dollars)

Description	GRC Adopted 1993	Attrition 1994	Attrition 1995
Fixed capital - Weighted Average	(a)	(b)	(c)
Plant in Service - 1993 BOY	$ 4,029,878	$ 4,270,008	$ 4,501,669
PHFU	0	0	0
Total Fixed Capital - 1993 BOY	4,029,878	4,270,008	4,501,669
1993 Plant Additions - Wtd. Avg.	114,503	103,637	117,275
Total Fixed Capital - Wtd. Avg.	$ 4,144,381	$ 4,373,645	$ 4,618,944
Customer Advance for Construction	($ 28,549)	($ 28,549)	($ 28,549)
Working Capital			
Materials & Supplies	42,507	42,507	42,507
Working Cash	7,916	7,916	7,916
Total Working Capital	$ 50,423	$ 50,423	$ 50,423
Tot. Before Deduction for Reserve	$ 4,166,255	$ 4,395,519	$ 4,640,818
Deductions for Reserves			
Depreciation	(1,480,154)	(1,641,160)	(1,811,135)
Deferred Income Taxes	(278,384)	(284,733)	(289,573)
Amortization & Other	(13,733)	(17,596)	(21,459)
Total Deduction for Reserves	($ 1,772,271)	($ 1,943,489)	($ 2,122,167)
WTD. AVG. DEPRECIATED RATE BASE	$ 2,393,984	$ 2,452,030	$ 2,518,651

APPENDIX I

SAN DIEGO GAS & ELECTRIC COMPANY

GAS DEPARTMENT

ATTRITION REVENUE [*271] REQUIREMENT ESTIMATES

ATTRITION BASE RATE REVENUE REQUIREMENT ESTIMATES

(Thousands of Dollars)

Description	GRC Adopted 1993 (a)	Incremt. Attrition 1994 (b)	Attrition 1994 (c)
Operating Revenues			
Base Rate Revenues - Retail	$ 161,520	$ 10,449	$ 171,969
Interdepartmental	11,901	0	11,901
Miscellaneous	2,804	0	2,804
Total Operating Revenues	$ 176,225	$ 10,449	$ 186,674
Operating Expenses			
Supply	594	56	650
Storage	279	11	290
Transmission	5,886	183	6,068
Distribution	21,151	754	21,905
Customer Accounts	15,809	535	16,344
Uncollectibles	443	29	471
Demand-Side-Management	9,670	397	10,067
Marketing (Non-DSM)	0	0	0
Administrative & General	28,196	594	28,789
Franchise Requirements	3,521	228	3,749
Other Adjustment	(594)	(20)	(614)
Subtotal	$ 84,954	$ 2,765	$ 87,720
Depreciation	29,139	2,400	31,539
Taxes Other Than On Income	7,049	378	7,427
Taxes On Income	18,742	2,389	21,131
Total Operating Expenses	$ 139,884	$ 7,932	$ 147,816
Net Operating Income	$ 36,341	$ 2,517	$ 38,858
Rate Base	$ 365,601	$ 25,320	$ 390,921
Rate of Return	9.94%	9.94%	9.94%
DSM 1990 & 1991 Rewards n1	$ 297	$ 192	$ 489
DSM Balancing Account Amort. n2	$ 2,296	$ 0	$ 2,296

Description	GRC Adopted 1993 (a)	Incremt. Attrition 1994 (b)	Attrition 1994 (c)
Total Base Rate Rev.	$ 178,818	$ 10,641	$ 189,459

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Description	Incremt. Attrition 1995 (d)	Attrition 1995 (e)
Operating Revenues		
Base Rate Revenues - Retail	$ 8,482	$ 180,450
Interdepartmental	0	11,901
Miscellaneous	0	2,804
Total Operating Revenues	$ 8,482	$ 195,155
Operating Expenses		
Supply	61	711
Storage	12	302
Transmission	202	6,270
Distribution	822	22,727
Customer Accounts	590	16,935
Uncollectibles	23	494
Demand-Side-Management	455	10,522
Marketing (Non-DSM)	0	0
Administrative & General	662	29,451
Franchise Requirements	185	3,934
Other Adjustment	(21)	(635)
Subtotal	$ 2,991	$ 90,711
Depreciation	2,202	33,741
Taxes Other Than On Income	436	7,863
Taxes On Income	993	22,124
Total Operating Expenses	$ 6,622	$ 154,438
Net Operating Income	$ 1,859	$ 40,717
Rate Base	$ 18,707	$ 409,628
Rate of Return	9.94%	9.94%
DSM 1990 & 1991 Rewards n1	$ 0	$ 489
DSM Balancing Account Amort. n2	$ 0	$ 2,296
Total Base Rate Rev.	$ 8,482	$ 197,941

n1 As shown in Appendix B, Page 5 of 5.

n2 As shown in Appendix B, Page 5 of 5. The amortized amount for 1994 & 1995 should be updated in the attrition filings.

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SUMMARY OF ATTRITION INCREMENTAL REVENUE REQUIREMENTS

(Thousands of Dollars)

Description	Incremt. Attrition 1994 (a)	Incremt. Attrition 1995 (b)
O&M Expenses		
Labor Escalation	$ 1,332	$ 1,421
Non-Labor Escalation	1,177	1,362
Subtotal	$ 2,509	$ 2,783
Franchise Fees & Uncollectibles	63	70
Total O&M Expenses	$ 2,572	$ 2,853
Capital Related		
Depreciation	$ 4,233	$ 3,884
Ad Valorem Tax	388	447
Income Taxes	(658)	(1,586)
Rate Base	3,722	2,746
Subtotal	$ 7,684	$ 5,491
Franchise Fees & Uncollectibles	193	138
Total Capital Related	$ 7,877	$ 5,629
Total Oper. Attr. Incr. Rev. Reqt.	$ 10,449	$ 8,482
DSM 1990 & 1991 Rewards n1	$ 192	$ 0
DSM Balancing Account Amort. n2	$ 0	$ 0
Total Attr. Incr. Rev. Reqt.	$ 10,641	$ 8,482

n1 Including FF&U.

n2 Including FF&U. The amortized amounts for 1994 & 1995 should be updated in SDG&E's attrition filings.

ESCALATION RATES FOR ATTRITION YEARS

(Base Year 1993)

Labor	Non-Labor

Year	Rate	Index	Rate	Index
1. Adopted Escalation Rates for Test Year 1993 n1				
1988	--	100.0	--	100.0
1989	3.82%	103.8	4.76%	104.8
1990	3.94%	107.9	3.55%	108.5
1991	4.51%	112.8	3.31%	112.1
1992	4.33%	117.7	2.17%	114.5
1993	3.47%	121.7	3.43%	118.4
2. Estimated Escalation Rates for Attrition Years n2				
1993	--	100.0	--	100.0
1994	3.37%	103.4	4.25%	104.2
1995	3.48%	107.0	4.71%	109.2

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n1 As shown in Appendix D, Page 1 of 1.

n2 As estimated in SDG&E's Updated Results of Opr. (Exh. 64, Page 14-15). Actual escalation rates for attrition year 1994 & 1995 should be updated in SDG&E's attrition filings.

ATTRITION INCREMENTAL O&M EXPENSES

(Thousands of Dollars)

Description	GRC Adopted 1993 (a)	Transfer of Other to Labor/ Non-Labor (b)	Total for 1994 Attrition Purpose (c)	Attrition 1994 (d)
Operating Expenses				
Supply				
Labor	$ 1,252	0	$ 1,252	$ 1,294
Non-Labor	322	0	322	336
Other	(980)	0	(980)	(980)
Total Supply	$ 594	$ 0	$ 594	$ 650
Storage				
Labor	94	0	$ 94	$ 97
Non-Labor	185	0	185	193
Other	0	0	0	0
Total Storage	$ 279	$ 0	$ 279	$ 290
Transmission				
Labor	3,147	0	3,147	3,253
Non-Labor	1,804	0	1,804	1,881
Other	934	0	934	934
Total Transmission	$ 5,886	$ 0	$ 5,886	$ 6,068

Description	GRC Adopted 1993 (a)	Transfer of Other to Labor/ Non-Labor (b)	Total for 1994 Attrition Purpose (c)	Attrition 1994 (d)
Distribution				
Labor	16,450	0	16,450	17,005
Non-Labor	4,700	0	4,700	4,900
Other	0	0	0	0
Total Distribution	$ 21,151	$ 0	$ 21,151	$ 21,905
Customer Accounts				
Labor	9,358	0	9,358	9,673
Non-Labor	5,167	0	5,167	5,386
Other (Less Uncoll.)	1,285	0	1,285	1,285
Total Customer Acct.	$ 15,809	$ 0	$ 15,809	$ 16,344
Marketing (DSM)				
Labor	$ 1,546	$ 0	$ 1,546	$ 1,598
Non-Labor	8,124	0	8,124	8,469
Other	0	0	0	0
Total Marketing	$ 9,670	$ 0	$ 9,670	$ 10,067
Administrative & General				
Labor	8,268	0	8,268	8,547
Non-Labor	7,417	0	7,417	7,731
Other (Less Franchise Fees)	12,511	0	12,511	12,511
Total A&G	$ 28,196	$ 0	$ 28,196	$ 28,789
Other Adjustment				
Labor	(594)	0	(594)	(614)
Total Labor	39,521	0	39,521	40,853
Total Non-Labor	27,720	0	27,720	28,897
Total Other (Less FF&U)	13,750	0	13,750	13,750
Total O&M (Less FF&U)	$ 80,991	$ 0	$ 80,991	$ 83,500
Increment for Attrition				$ 2,509

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Description	Attrition 1995 (e)
Operating Expenses	
Supply	
Labor	$ 1,340
Non-Labor	352
Other	(980)
Total Supply	$ 711

Description	Attrition 1995 (e)
Storage	
Labor	$ 100
Non-Labor	202
Other	0
Total Storage	$ 302
Transmission	
Labor	3,366
Non-Labor	1,970
Other	934
Total Transmission	$ 6,270
Distribution	
Labor	17,596
Non-Labor	5,131
Other	0
Total Distribution	$ 22,727
Customer Accounts	
Labor	10,009
Non-Labor	5,640
Other (Less Uncoll.)	1,285
Total Customer Acct.	$ 16,935
Marketing (DSM)	
Labor	$ 1,653
Non-Labor	8,868
Other	0
Total Marketing	$ 10,522
Administrative & General	
Labor	8,844
Non-Labor	8,096
Other (Less Franchise Fees)	12,511
Total A&G	$ 29,451
Other Adjustment	
Labor	(635)
Total Labor	42,274
Total Non-Labor	30,258
Total Other (Less FF&U)	13,750
Total O&M (Less FF&U)	$ 86,282
Increment for Attrition	$ 2,783

INCOME TAX ADJUSTMENTS FOR ATTRITION YEARS

(Thousands of Dollars)

Description	GRC Adopted 1993 (a)	Incremt. Attrition 1994 (b)	Attrition 1994 (c)
California Income Tax Adjustments			
State Tax Depreciation	$ 24,646	$ 1,780	$ 26,426
Book Depreciation	(28,021)	(2,400)	(30,421)
Other Adjustments	2,689	0	2,689
TOTAL CCFT ADJUSTMENTS	($ 686)	($ 620)	($ 1,306)
Federal Income Tax Adjustments			
Federal Tax Depreciation	$ 19,868	$ 1,435	$ 21,303
Book Depreciation	(28,021)	(2,400)	(30,421)
Other Adjustments	500	0	500
TOTAL FIT ADJUSTMENTS	($ 7,653)	($ 965)	($ 8,618)
Interest Charges			
Rate Base	$ 365,601	$ 25,320	$ 390,921
Unamortized ITC	(7,998)	377	(7,621)
Adjusted Rate Base	$ 357,603	$ 25,697	$ 383,300
Wtd. Cost of Long Term Debt	3.660%	3.660%	3.660%
State Allocation	$ 13,088	$ 941	$ 14,029
Federal Allocation	$ 13,381	$ 927	$ 14,308

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Description	Incremt. Attrition 1995 (d)	Attrition 1995 (e)
California Income Tax Adjustments		
State Tax Depreciation	$ 2,051	$ 28,477
Book Depreciation	(2,202)	(32,623)
Other Adjustments	0	2,689
TOTAL CCFT ADJUSTMENTS	($ 151)	($ 1,457)
Federal Income Tax Adjustments		
Federal Tax Depreciation	$ 1,653	$ 22,956
Book Depreciation	(2,202)	(32,623)
Other Adjustments	0	500
TOTAL FIT ADJUSTMENTS	($ 549)	($ 9,167)

Description	Incremt. Attrition 1995 (d)	Attrition 1995 (e)
Interest Charges		
Rate Base	$ 18,707	$ 409,628
Unamortized ITC	377	(7,244)
Adjusted Rate Base	$ 19,084	$ 402,384
Wtd. Cost of Long Term Debt	3.660%	3.660%
State Allocation	$ 698	$ 14,727
Federal Allocation	$ 685	$ 14,992

TAXES ON INCOME FOR ATTRITION YEARS

(Thousands of Dollars)

Description	GRC Adopted 1993 (a)	Attrition 1994 (b)	Attrition 1995 (c)
Calif. Corporation Franchise Tax			
Operating Revenues	$ 176,225	$ 186,674	$ 195,155
Operating Expenses (Incl. Depr.)	114,093	119,259	124,452
Taxes Other Than on Income	7,049	7,427	7,863
Interest Charges	13,088	14,029	14,727
State Income Tax Adjustments	(686)	(1,306)	(1,457)
California Taxable Income	$ 42,680	$ 47,265	$ 49,571
CCFT Rate	9.3%	9.3%	9.3%
TOTAL CCFT	$ 3,969	$ 4,396	$ 4,610
Federal Income Tax			
Operating Revenues	$ 176,225	$ 186,674	$ 195,155
Operating Expenses	114,093	119,259	124,452
Taxes Other Than on Income	7,049	7,427	7,863
Interest Charges	13,381	14,308	14,992
CCFT - Prior Year	4,797	3,969	4,396
Federal Income Tax Adjustments	(7,653)	(8,618)	(9,167)
Federal Taxable Income	$ 44,558	$ 50,329	$ 52,620
FIT Tax Rate	34%	34%	34%
Federal Income Tax	$ 15,150	$ 17,112	$ 17,891
Amortization of ITC	(377)	(377)	(377)

Description	GRC Adopted 1993 (a)	Attrition 1994 (b)	Attrition 1995 (c)
Total Federal Income Tax	$ 14,773	$ 16,735	$ 17,514
TOTAL TAXES ON INCOME	$ 18,742	$ 21,131	$ 22,124

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RATE BASE FOR ATTRITION YEARS

(Thousands of Dollars)

Description	GRC Adopted 1993 (a)	Attrition 1994 (b)	Attrition 1995 (c)
Fixed Capital - Weighted Average			
Plant in Service - 1993 BOY	$ 663,182	$ 720,933	$ 773,001
PHFU	0	0	0
Total Fixed Capital - 1993 BOY	663,182	720,933	773,001
1993 Plant Additions - Wtd. Avg.	21,282	22,152	23,874
Total Fixed Capital - Wtd. Avg.	$ 684,464	$ 743,085	$ 796,875
Customer Advance for Construction	($ 14,085)	($ 14,085)	($ 14,085)
Working Capital			
Fuel in Storage	172	172	172
Materials & Supplies	2,755	2,755	2,755
Working Cash	3,365	3,365	3,365
Total Working Capital	$ 6,292	$ 6,292	$ 6,292
Tot. Before Deduction for Reserve	$ 676,671	$ 735,292	$ 789,082
Deductions for Reserves			
Depreciation	(289,081)	(317,483)	(348,122)
Deferred Income Taxes	(18,077)	(21,858)	(25,184)
Amortization & Other	(3,912)	(5,030)	(6,148)
Total Deduction for Reserves	($ 311,070)	($ 344,371)	($ 379,454)
WTD. AVG. DEPRECIATED RATE BASE	$ 365,601	$ 390,921	$ 409,628

APPENDIX J

SAN DIEGO GAS & ELECTRIC COMPANY

STEAM DEPARTMENT

ATTRITION BASE RATE REVENUE REQUIREMENT [*278] ESTIMATES

(Thousands of Dollars)

Description	GRC Adopted 1993 (a)	Incremt. Attrition 1994 (b)	Attrition 1994 (c)	Incremt. Attrition 1995 (d)	Attrition 1995 (e)
Operating Revenues					
Base Rate Revenues - Retail	$ 1,608	($ 10)	$ 1,598	$ 53	$ 1,651
Miscellaneous	0	0	0	0	0
Non-Jurisdictional	0	0	0	0	0
Total Operating Revenues	$ 1,608	($ 10)	$ 1,598	$ 53	$ 1,651
Operating Expenses					
Production	715	27	742	30	772
Distribution	76	3	79	3	82
Customer Accounts	5	0	5	0	5
Uncollectibles	0	0	0	0	0
Administrative & General	343	6	349	6	356
Franchise Requirements	34	(0)	34	1	35
Other Adjustment	(13)	(0)	(14)	(0)	(14)
Subtotal	$ 1,160	$ 35	$ 1,195	$ 40	$ 1,235
Depreciation	251	2	253	8	261
Taxes Other Than On Income	51	1	52	0	52
Taxes On Income	84	(30)	53	8	62
Total Operating Expenses	$ 1,546	$ 8	$ 1,553	$ 56	$ 1,610
Net Operating Income	$ 62	($ 18)	$ 45	($ 3)	$ 41
Rate Base	$ 625	($ 177)	$ 448	($ 35)	$ 413
Rate of Return	9.94%	9.94%	9.94%	9.94%	9.94%

SUMMARY OF ATTRITION INCREMENTAL [*279] REVENUE REQUIREMENTS

(Thousands of Dollars)

Description	Incremt. Attrition 1994 (a)	Incremt. Attrition 1995 (b)
O&M Expenses		
Labor Escalation	$ 18	$ 19
Non-Labor Escalation	17	20
Subtotal	$ 35	$ 39
Franchise Fees & Uncollectibles	1	1
Total O&M Expenses	$ 36	$ 40
Capital Related		
Depreciation	$ 4	$ 14
Ad Valorem Tax	1	0
Income Taxes	(23)	4
Rate Base	(26)	(5)
Subtotal	($ 45)	$ 13
Franchise Fees & Uncollectibles	(1)	0
Total Capital Related	($ 46)	$ 13
Total Oper. Att. Incr. Rev. Reqt.	($ 10)	$ 53

ESCALATION RATES FOR ATTRITION YEARS

(Base Year 1993)

	Labor		Non-Labor	
Year	Rate	Index	Rate	Index
1. Adopted Escalation Rates for Test Year 1993 n1				
1988	--	100.0	--	100.0
1989	3.82%	103.8	4.76%	104.8
1990	3.94%	107.9	3.55%	108.5
1991	4.51%	112.8	3.31%	112.1
1992	4.33%	117.7	2.17%	114.5
1993	3.47%	121.7	3.43%	118.4
2. Estimated Escalation Rates for Attrition Years n2				
1993	--	100.0	--	100.0
1994	3.37%	103.4	4.25%	104.2
1995	3.48%	107.0	4.71%	109.2

n1 As shown in Appendix D, Page 1 of 1.

n2 As estimated in SDG&E's Updated Results of Opr. (Exh. 64, Page 14-15). Actual escalation rates for attrition year 1994 & 1995 should be updated in SDG&E's attrition filings.

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ATTRITION INCREMENTAL O&M EXPENSES

(Thousands of Dollars)

Description	GRC Adopted 1993 (a)	Transfer of Other to Labor/ Non-Labor (b)	Total for 1994 Attrition Purpose (c)	Attrition 1994 (d)	Attrition 1995 (e)
Operating Expenses					
Production					
Labor	$ 399	0	$ 399	$ 413	$ 427
Non-Labor	316	0	316	330	345
Other	0	0	0	0	0
Total Production	$ 715	$ 0	$ 715	$ 742	$ 772
Distribution					
Labor	57	0	57	59	61
Non-Labor	19	0	19	20	21
Other	0	0	0	0	0
Total Distribution	$ 76	$ 0	$ 76	$ 79	$ 82
Customer Accounts					
Labor	4	0	4	4	4
Non-Labor	1	0	1	1	1
Other (Less Uncoll.)	0	0	0	0	0
Total Customer Acct.	$ 5	$ 0	$ 5	$ 5	$ 5
Administrative & General					
Labor	83	0	83	86	89
Non-Labor	68	0	68	71	74
Other (Less Franchise Fees)	192	0	192	192	192
Total A&G	$ 344	$ 0	$ 344	$ 349	$ 356
Other Adjustment					
Labor	(13)	0	(13)	(14)	(14)
Total Labor	530	0	530	548	567
Total Non-Labor	404	0	404	422	441
Total Other (Less FF&U)	192	0	192	192	192
Total O&M (Less FF&U)	$ 1,126	$ 0	$ 1,126	$ 1,161	$ 1,200
Increment for Attrition				$ 35	$ 39

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INCOME TAX ADJUSTMENTS FOR ATTRITION YEARS

(Thousands of Dollars)

Description	GRC Adopted 1993 (a)	Incremt. Attrition 1994 (b)	Attrition 1994 (c)	Incremt. Attrition 1995 (d)	Attrition 1995 (e)
California Income Tax Adjustments					
State Tax Depreciation	$ 121	$ 5	$ 126	($ 1)	$ 125
Book Depreciation	(251)	(2)	(253)	(8)	(261)
Other Adjustments	11	0	11	0	11
TOTAL CCFT ADJUSTMENTS	($ 119)	$ 3	($ 116)	($ 9)	($ 125)
Federal Income Tax Adjustments					
Federal Tax Depreciation		$ 9	$ 9	($ 2)	$ 7
Book Depreciation	(251)	(2)	(253)	(8)	(261)
Other Adjustments	200	0	200	0	200
TOTAL FIT ADJUSTMENTS	($ 51)	$ 7	($ 44)	($ 10)	($ 54)
Interest Charges					
Rate Base	$ 625	($ 177)	$ 448	($ 35)	$ 413
Unamortized ITC	0	0	0	0	0
Adjusted Rate Base	$ 625	($ 177)	$ 448	($ 35)	$ 413
Wtd. Cost of Long Term Debt	3.660%	3.660%	3.660%	3.660%	3.660%
State Allocation	$ 23	($ 6)	$ 16	($ 1)	$ 15
Federal Allocation	$ 23	($ 6)	$ 16	($ 1)	$ 15

TAXES ON INCOME FOR ATTRITION YEARS

(Thousands of Dollars)

Description	GRC Adopted 1993 (a)	Attrition 1994 (b)	Attrition 1995 (c)
Calif. Corporation Franchise Tax			
Operating Revenues	$ 1,608	$ 1,598	$ 1,651
Operating Expenses (Incl. Depr.)	1,411	1,448	1,496
Taxes Other Than on Income	51	52	52
Interest Charges	23	16	15
State Income Tax Adjustments	(119)	(116)	(125)

Description	GRC Adopted 1993 (a)	Attrition 1994 (b)	Attrition 1995 (c)
California Taxable Income	$ 242	$ 197	$ 212
CCFT Rate	9.3%	9.3%	9.3%
TOTAL CCFT	$ 22	$ 18	$ 20
Federal Income Tax			
Operating Revenues	$ 1,608	$ 1,598	$ 1,651
Operating Expenses	1,411	1,448	1,496
Taxes Other Than on Income	51	52	52
Interest Charges	23	16	15
CCFT - Prior Year	(6)	22	18
Federal Income Tax Adjustments	(51)	(44)	(54)
Federal Taxable Income	$ 180	$ 103	$ 123
FIT Tax Rate	34%	34%	34%
Federal Income Tax	$ 61	$ 35	$ 42
Amortization of ITC	0	0	0
Total Federal Income Tax	$ 61	$ 35	$ 42
TOTAL TAXES ON INCOME	$ 84	$ 53	$ 62

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RATE BASE FOR ATTRITION YEARS

(Thousands of Dollars)

Description	GRC Adopted 1993 (a)	Attrition 1994 (b)	Attrition 1995 (c)
Fixed Capital - Weighted Average			
Plant in Service - 1993 BOY	$ 6,140	$ 6,158	$ 6,431
PHFU	0	0	0
Total Fixed Capital - 1993 BOY	6,140	6,158	6,431
1993 Plant Additions - Wtd. Avg.	9	49	(19)
Total Fixed Capital - Wtd. Avg.	$ 6,149	$ 6,207	$ 6,412
Customer Advance for Construction	$ 0	$ 0	$ 0
Working Capital			

Description	GRC Adopted 1993	Attrition 1994	Attrition 1995
Fixed Capital - Weighted Average	(a)	(b)	(c)
Materials & Supplies	15	15	15
Working Cash	79	79	79
Total Working Capital	$ 94	$ 94	$ 94
Tot. Before Deduction for Reserve	$ 6,243	$ 6,301	$ 6,506
Deductions for Reserves			
Depreciation	(5,614)	(5,849)	(6,089)
Deferred Income Taxes	0	0	0
Amortization & Other	(4)	(4)	(4)
Total Deduction for Reserves	($ 5,618)	($ 5,853)	($ 6,093)
WTD. AVG. DEPRECIATED RATE BASE	$ 625	$ 448	$ 413

APPENDIX K

SAN DIEGO GAS & ELECTRIC COMPANY

ELECTRIC DEPARTMENT

Forecast Period: Jan. 1, 1993 Through Dec. 31, 1993

SUMMARY OF CHANGES IN REVENUE REQUIREMENTS

(Thousands of 1993 Dollars)

Revenue Element	Present Rate Revenue (a)	Revenue Change (b)
BASE RATE REVENUES:		
- Authorized Margin (D.92-08-042) n1	$ 885,634	$ 0
- 1993 General Rate Case	0	47,008
- 1991 DSM Reward (1993 Recovery)	0	3,603
- DSM Balancing Acct. Amort. (EEBA)	0	3,395
Subtotal	$ 885,634	$ 54,006
- Sales Adjustment	17,575	(17,575)
Total Base Rate Revenue	$ 903,209	$ 36,431
ERAM BALANCING ACCOUNT RATE:	$ 19,227	$ 0
FUEL:		
- Energy Cost Ajustment Clause (ECAC) Offset	464,595	0
- ECAC Balancing Account	(29,652)	0
Total Fuel	$ 434,943	$ 0
ELECTRIC EFFICIENCY BAL. ACCT. (EEBA):		
- DSM offset rate	$ 21,433	($ 21,433)
SUBTOTAL	$ 1,378,812	$ 14,998
LOW INCOME RATE ASSISTANT (LIRA) PROGRAM:		
- LIRA Discount	(3,956)	(66)
- LIRA Surcharge	431	0
Total LIRA Program	($ 3,525)	($ 66)
TOTAL RETAIL REVENUES	$ 1,375,287	$ 14,933
Percentage Increase (Retail)		1.09%
Miscellaneous	17,005	(1,948)
Non-Jurisdictional	1,445	(70)
TOTAL REVENUES FOR ELECTRIC DEPARTMENT	$ 1,393,737	$ 12,915
Percentage Increase (Total Department)		0.93%

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Revenue Element	Adoped Revuenue (c)
BASE RATE REVENUES:	
- Authorized Margin (D.92-08-042) n1	$ 885,634
- 1993 General Rate Case	47,008
- 1991 DSM Reward (1993 Recovery)	3,603
- DSM Balancing Acct. Amort. (EEBA)	3,395
Subtotal	$ 939,640
- Sales Adjustment	0
Total Base Rate Revenue	$ 939,640

Revenue Element	Adoped Revuenue (c)
ERAM BALANCING ACCOUNT RATE:	$ 19,227
FUEL:	
- Energy Cost Ajustment Clause (ECAC) Offset	464,595
- ECAC Balancing Account	(29,652)
Total Fuel	$ 434,943
ELECTRIC EFFICIENCY BAL. ACCT. (EEBA):	
- DSM offset rate	$ 0
SUBTOTAL	$ 1,393,810
LOW INCOME RATE ASSISTANT (LIRA) PROGRAM:	
- LIRA Discount	(4,022)
- LIRA Surcharge	431
Total LIRA Program	($ 3,590)
TOTAL RETAIL REVENUES	$ 1,390,220
Percentage Increase (Retail)	
Miscellaneous	15,057
Non-Jurisdictional	1,375
TOTAL REVENUES FOR ELECTRIC DEPARTMENT	$ 1,406,652
Percentage Increase (Total Department)	

n1 Including 1990 DSM reward (1992 recovery) of $ 6,065,000 (D.91-12-074).

ADOPTED REVENUE ALLOWCATION

(SUMMARY)

CUSTOMER GROUP	ADOPTED SALES (GWHR) (A)	PRESENT REVENUE ($ 000's) (B)	PRESENT AVG RATE ($ /KWH) (C)
Residential	5,570.334	$ 602,567	$ 0.10817
Commercial/Industrial			
General Service (A)	1,771.451	181,399	0.10240
GS-Demand Metered 20kW (AD)	1,514.261	136,377	0.09006
Large TOU	5,589.331	432,502	0.07738
Total Commercial/Industrial	8,875.043	$ 750,278	$ 0.08454
Agriculture	159.355	$ 14,621	$ 0.09175
Lighting	74.410	$ 7,821	$ 0.10511
Total	14,679.142	$ 1,375,287	$ 0.09369

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CUSTOMER GROUP	ADOPTED REVENUE ($ 000's) (D)	ADOPTED AVG RATE ($/KWH) (E)	CHANGE IN REVENUE ($ 000'S) (F)	% (G)
Residential	$ 608,374	$ 0.10922	$ 5,807	1.0%
Commercial/Industrial				
General Service (A)	181,451	0.10243	52	0.0%
GS-Demand Metered 20kW (AD)	145,017	0.09577	8,640	6.3%
Large TOU	432,670	0.07741	168	0.0%

CUSTOMER GROUP	ADOPTED REVENUE ($ 000's) (D)	ADOPTED AVG RATE ($/KWH) (E)	CHANGE IN REVENUE ($ 000'S) (F)	% (G)
Total Commercial/Industrial	$ 759,138	$ 0.08554	$ 8,860	1.2%
Agriculture	$ 14,723	$ 0.09239	$ 102	0.7%
Lighting	$ 7,985	$ 0.10731	$ 164	2.1%
Total	$ 1,390,220	$ 0.09471	$ 14,933	1.1%

Column calculations:
(A) source: workpapers
(B) source: workpapers
(C) col B/col A/1,000
(D) source: Appendix K, Page 3 of 6.
(E) (col D)/col A/1,000
(F) col D-col B
(G) (col D-col B)/col B
Notes:
1. Presents the results of the Capped Equal Percentage of Marginal Cost (EPMC) revenue allocation based on adopted sales.
2. Present Rate Revenue uses 5/1/92 ECAC Rates.

(DETAIL)

UNADJUSTED MARGINAL COST REVENUE

CUSTOMER GROUP	MARG COST REVENUE ($ 000's) (A)	EPMC ALLOCATION FACTOR (B)	EPMC REVENUE ALLOCATION ($ 000's) (C)
Residential	$ 683,494	44.18%	$ 614,469
Commercial/Industrial			
General Service (A)	$ 200,873	12.99%	$ 180,587
GS-Demand Metered 20kW (AD)	174,896	11.31%	157,233
Large TOU	465,781	30.11%	418,743
Total Commercial/Industrial	$ 841,550	54.40%	$ 756,563
Agriculture	$ 16,411	1.06%	$ 14,754
Lighting	$ 5,485	0.35%	$ 4,931
Total	$ 1,546,940	100.00%	$ 1,390,717

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ADJUSTMENTS

CUSTOMER GROUP	NON-ALLOC REVENUE ($ 000's) (D)	LIRA ADJSTMT ($ 000's) (E)	ADOPTED REVENUE ($ 000's) (F)
Residential	$ 1	($ 3,861)	$ 608,374
Commercial/Industrial			
General Service (A)	$ 0	$ 52	$ 181,451
GS-Demand Metered 20kW (AD)	0	48	145,017
Large TOU	0	168	432,670
Total Commercial/Industrial	0	$ 268	$ 759,138

	ADJUSTMENTS		
	NON-ALLOC REVENUE ($ 000's)	LIRA ADJSTMT ($ 000's)	ADOPTED REVENUE ($ 000's)
CUSTOMER GROUP	(D)	(E)	(F)
Agriculture	$ 20	$ 3	$ 14,723
Lighting	$ 3,072	$ 0	$ 7,985
Total	$ 3,093	($ 3,590)	$ 1,390,220

Column Calculations:
(A) source: Appendix K, Page 4 of 6.
(B) % = marginal cost for group per col A/ total marginal cost per col A line 13.
(C) total EPMC revenue allocation per line 13= revenue requirements per workpapers. EPMC revenue allocation for each group = total EPMC revenue allocation X col B % for that group
(D) source: Appendix K, Page 4 of 6.
(E) LIRA (Low Income Ratepayer Assistance) Adjustment from Rate Design Chapter
(F) col K + col D + col E. adopted revenue includes Facility Charges and LIRA adjustment.
Notes:
1. Presents the adopted revenue requirement allocated among the customer groups based on the customer group marginal costs and EPMC revenue allocation method.

CAPPED ALLOCATION [*286] DETAIL

	CAPPED		
	VALUE BEFORE ADJUSTMENTS (% CHANGE)	MARGINAL COST ALLOCATOR	CAPPED ALLOCATION REVENUE ($ 000's)
CUSTOMER GROUP	(G)	(H)	(I)
Residential	N/A	$ 614,469	$ 0
Commercial/Industrial			
General Service (A)	0.0%	0	181,399
GS-Demand Metered 20kW (AD)	6.3%	0	144,969
Large TOU	0.0%	0	432,502
Total Commercial/Industrial			
Agriculture	N/A	14,754	0
Lighting	N/A	4,931	0
Total		$ 634,154	$ 758,870

	MARGINAL	TOTAL
	COST ALLOCATION REVENUE ($ 000's)	CAPPED EPMC ALLOCATION ($ 000's)
CUSTOMER GROUP	(J)	(K)
Residential	$ 612,234	$ 612,234
Commercial/Industrial		

CUSTOMER GROUP	MARGINAL COST ALLOCATION REVENUE ($ 000's) (J)	TOTAL CAPPED EPMC ALLOCATION ($ 000's) (K)
General Service (A)	0	181,399
GS-Demand Metered 20kW (AD)	0	144,969
Large TOU	0	432,502
Total Commercial/Industrial		
Agriculture	14,700	14,700
Lighting	4,913	4,913
Total	$ 631,847	$ 1,390,717

Column Calculations:
(G) Capped Percentage based on Present Revenue before Adjustments.
(H) Either zero or from col C.
(I) Either zero or capped class allocation.
(J) Allocation of remaining revenue to classes using col H allocators.
(K) Sum of col I and col J.
Notes:
1. Presents the adopted revenue requirement allocated among [*287] the customer groups based on the customer group marginal costs and EPMC revenue allocation method.

ADOPTED MARGINAL COST REVENUE

			MARGINAL	COST REVENUE
CUSTOMER GROUP	CUSTOMER ($ 000's) (A)	DEMAND ($ 000's) (B)	ENERGY ($ 000's) (C)	TOTAL ($ 000's) (D)
Residential	110,353	394,039	179,102	683,494
Commercial/Industrial				
General Service (A)	17,557	126,424	56,893	200,873
GS-Demand Metered 20kW (AD)	3,089	115,051	56,756	174,896
Large TOU	20,640	273,711	171,430	465,781
Total Commercial/Industrial	41,285	515,186	285,079	841,550
Agriculture	2,282	9,073	5,056	16,411
Lighting	666	2,484	2,335	5,485
Total	154,586	920,782	471,572	1,546,940

Column Calculations:
(A) source: Appendix K, Page 5 of 6.
(B) source: Appendix K, Page 5 of 6.
(C) source: 92 ECAC values ratioed by ECAC Sales to GRC Sales
(D) col A + col B + col C
Notes:

1. Presents the classifications of marginal cost revenue and disaggregation of non-allocated revenues by customer group.

NON-ALLOCATED REVENUES

CUSTOMER GROUP	STREET-LIGHTG CHARGES ($ 000's) (E)	TOU METER CHARGES ($ 000's) (F)	FACILITY CHARGES ($ 000's) (G)
Residential	0	1	1
Commercial/Industrial			
General Service (A)	0	0	0
GS-Demand Metered 20kW (AD)	0	0	0
Large TOU	0	0	0
Total Commercial/Industrial	0	0	0
Agriculture	0	20	20
Lighting	3,072	0	3,072
Total	3,072	21	3,093

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Column Calculations:

(E) & (F) source: workpapers

(G) col E + col F

Notes:

1. Presents the classifications of marginal cost revenue and disaggregation of non-allocated revenues by customer group.

ADOPTED MARGINAL CUSTOMER COST REVENUE

CUSTOMER GROUP	UNIT MARGINAL CUSTOMER COST ($/CUSTOMER) (A)	NUMBER OF CUSTOMERS (B)	MARGINAL CUSTOMER COST REVENUE ($ 000's) (C)
Residential	108.37	1,018,303	110,353
Commercial/Industrial			
General Service (A)	175.04	100,302	17,557
GS-Demand Metered 20kW (AD)	578.38	5,340	3,089
Large TOU	2,741.72	7,528	20,640
Total Commercial/Industrial		113,170	41,285
Agriculture	620.22	3,679	2,282
	($/KWHR)	GWHR	($ 000's)
Lighting	0.00895	74,410	666
Total			154,586

Column Calculations:

(A) Source: 1992 ECAC Decision, D.92-04-061, Appen A Table 6

(B) source: workpapers tp 1993 GRC Exhibit

(C) col A X col B / 1,000 except for totals (lines 7, 13 and 15)

Notes:

1. Presents the calculation of the customer cost component of marginal cost revenue by customer group.

ADOPTED MARGINAL DEMAND COST REVENUE

(SUMMARY)

CUSTOMER GROUP	GENERATION ($ 000'S) (A)	TRANSMISSION ($ 000'S) (B)	DISTRIBUTION ($ 000'S) (C)
Residential	95,753	41,477	256,808
Commercial/Industrial			
General Service (A)	39,203	14,213	73,008
GS-Demand Metered 20kW (AD)	35,181	12,881	66,988
Large TOU	97,246	32,078	144,387
Total Commercial/Industrial	171,630	59,172	284,383
Agriculture	2,133	947	5,992
Lighting	626	264	1,594
Total	270,143	101,861	548,777

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CUSTOMER GROUP	TOTAL ($ 000'S) (D)
Residential	394,039
Commercial/Industrial	
General Service (A)	126,424
GS-Demand Metered 20kW (AD)	115,051
Large TOU	273,711
Total Commercial/Industrial	515,186
Agriculture	9,073
Lighting	2,484
Total	920,782

Column Calculations:

Cols (A) to (C) - Based on 1992 ECAC Decision, D.92-04-061, Appen A Table 4 marginal demand values times the ratio of 1992 ECAC Sales to 1993 GRC Sales

(D) col A + col B + col C

Notes:

1. Presents the functionalization of the demand cost component of marginal cost revenue by customer group.

SUMMARY OF RESIDENTIAL RATES

DESCRIPTION (A)	UNITS (B)	9/2/92 PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)
SCHEDULE DR					
Baseline Energy	$ /Kwh	0.09741	0.09847	0.00106	1.09
Non-Baseline Energy	$ /Kwh	0.12297	0.12403	0.00106	0.86
Minimum Bill	$ /Day	0.164	0.164	0.000	0.00
SCHEDULE DR-LI					

DESCRIPTION (A)	UNITS (B)	9/2/92 PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	CHANGE % (F)
Baseline Energy	$ /Kwh	0.08277	0.08367	0.00090	1.09
Non-Baseline Energy	$ /Kwh	0.10450	0.10540	0.00090	0.86
Minimum Bill	$ /Day	0.139	0.139	0.000	0.00
SCHEDULE DM					
Baseline Energy	$ /Kwh	0.09741	0.09847	0.00106	1.09
Non-Baseline Energy	$ /Kwh	0.12297	0.12403	0.00106	0.86
Minimum Bill	$ /Day	0.164	0.164	0.000	0.00
SCHEDULE DS					
Baseline Energy	$ /Kwh	0.09741	0.09847	0.00106	1.09
Non-Baseline Energy	$ /Kwh	0.12297	0.12403	0.00106	0.86
Baseline Energy L/I	$ /Kwh	0.08277	0.08367	0.00090	1.09
Non-Baseline Energy L/I	$ /Kwh	0.10450	0.10540	0.00090	0.86
Unit Discount	$ /Day	0.110	0.110	0.000	0.00
Minimum Bill	$ /Day	0.164	0.164	0.000	0.00
Minimum Bill - L/I	$ /Day	0.139	0.139	0.000	0.00
SCHEDULE DT					
Baseline Energy	$ /Kwh	0.09741	0.09847	0.00106	1.09
Non-Baseline Energy	$ /Kwh	0.12297	0.12403	0.00106	0.86
Baseline Energy L/I	$ /Kwh	0.08277	0.08367	0.00090	1.09
Non-Baseline Energy L/I	$ /Kwh	0.10450	0.10540	0.00090	0.86
Space Discount	$ /Day	0.312	0.312	0.000	0.00
Minimum Bill	$ /Day	0.164	0.164	0.000	0.00
Minimum Bill - L/I	$ /Day	0.139	0.139	0.000	0.00
SCHEDULE D-SMF					
Customer Charge	$ /Month	30.00	30.00	0.00	0.00
On-Peak Demand	$ /KW	9.69	9.67	-0.02	(0.21)
Baseline Energy	$ /Kwh	0.08018	0.08120	0.00102	1.27
Non-Baseline Energy	$ /Kwh	0.10121	0.10227	0.00106	1.05
Baseline Energy L/I	$ /Kwh	0.06815	0.06902	0.00087	1.27
Non-Baseline Energy L/I	$ /Kwh	0.08603	0.08693	0.00090	1.05
Unit Discount	$ /Kwh	0.110	0.110	0.000	0.00
Space Discount	$ /Kwh	0.312	0.312	0.000	0.00
SCHEDULE DR-TOU					
Minimum Bill	$ /Day	0.164	0.164	0.000	0.00
Metering Charge	$ /Day	3.28	3.28	0.00	0.00
On-Peak Energy: Summer	$ /Kwh	0.32426	0.32705	0.00279	0.86
Off-Peak Energy: Summer	$ /Kwh	0.07956	0.08025	0.00069	0.86
On-Peak Energy: Winter	$ /Kwh	0.12768	0.12878	0.00110	0.86
Off-Peak Energy: Winter	$ /Kwh	0.07956	0.08025	0.00069	0.86
Baseline Adjustment	$ /Kwh	0.02556	0.02556	0.00000	0.00
SCHEDULE DR-TOU-2					
Minimum Bill	$ /Day	0.164	0.164	0.000	0.00
Metering Charge	$ /Day	3.28	3.28	0.00	0.00
On-Peak Energy: Summer	$ /Kwh	0.28294	0.28574	0.00280	0.99
Off-Peak Energy: Summer	$ /Kwh	0.06943	0.07011	0.00068	0.98
On-Peak Energy: Winter	$ /Kwh	0.11141	0.11251	0.00110	0.99
Off-Peak Energy: Winter	$ /Kwh	0.06943	0.07011	0.00068	0.98

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Note:

- Column C: Includes rate adjustments ordered in D.92-04-061 & D.92-04-085 (SDG&E's 1992 ECAC proceeding), effective 5/1/92.
- Column D: From rate design workpapers
- Column E: Column D - Column C
- Column F: (Column E / Column C) * 100
- L/I represents Low-Income

Note: D-ATOU and D-UTOU were eliminated 1/1/92.

SUMMARY OF COMMERCIAL AND INDUSTRIAL RATES

		9/2/92		CHANGE	
		PRESENT	ADOPTED		
DESCRIPTION	UNITS	RATE	RATE	AMOUNT	%
(A)	(B)	(C)	(D)	(E)	(F)
SCHEDULE A					
Customer Charge	$ /Month	5.00	5.00	0.00	0.00
Energy Charge	$ /Kwh	0.09814	0.09816	0.00002	0.02
SCHEDULE AD					
Customer Charge	$ /Month	15.00	15.00	0.00	0.00
Demand Charge	$ /KW	6.74	7.17	0.43	6.36
Energy Charge	$ /Kwh	0.06671	0.07096	0.00425	6.37
On-Peak Rate Limiter: Summer	$ /Kwh	0.74	0.74	0.00	0.00
On-Peak Rate Limiter: Winter	$ /Kwh	0.29	0.29	0.00	0.00
SCHEDULE AL-TOU (Default Times)					
Service Charge	$ /Month	30.00	30.00	0.00	0.00
On-Peak Rate Limiter: Summer	$ /Kwh	0.74	0.74	0.00	0.00
On-Peak Rate Limiter: Winter	$ /Kwh	0.29	0.29	0.00	0.00
Average Rate Limiter	$ /Kwh	5.00	5.00	0.00	0.00
Non-Coincident Demand					
Secondary	$ /KW	3.71	3.70	(0.01)	(0.27)
Primary	$ /KW	2.95	2.95	0.00	0.00
Transmission	$ /KW	1.24	1.24	0.00	0.00
On-Peak Demand: Summer					
Secondary	$ /KW	17.54	17.52	(0.02)	(0.11)
Primary	$ /KW	17.54	17.52	(0.02)	(0.11)
Transmission	$ /KW	11.03	11.02	(0.01)	(0.09)
On-Peak Demand: Winter					
Secondary	$ /KW	4.08	4.07	(0.01)	(0.25)
Primary	$ /KW	4.08	4.07	(0.01)	(0.25)
Transmission	$ /KW	1.64	1.64	0.00	0.00
On-Peak Energy: Summer					
Secondary	$ /Kwh	0.07708	0.07698	(0.00010)	(0.13)
Primary	$ /Kwh	0.07211	0.07201	(0.00010)	(0.14)
Transmission	$ /Kwh	0.06995	0.06986	(0.00009)	(0.13)
Semi-Peak Energy: Summer					
Secondary	$ /Kwh	0.04984	0.04977	(0.00007)	(0.14)
Primary	$ /Kwh	0.04747	0.04741	(0.00006)	(0.13)
Transmission	$ /Kwh	0.04605	0.04599	(0.00006)	(0.13)
Off-Peak Energy: Summer					
Secondary	$ /Kwh	0.03770	0.03765	(0.00005)	(0.13)
Primary	$ /Kwh	0.03528	0.03523	(0.00005)	(0.14)
Transmission	$ /Kwh	0.03423	0.03418	(0.00005)	(0.15)

DESCRIPTION (A)	UNITS (B)	9/2/92 PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	% (F)
On-Peak Energy: Winter					
Secondary	$ /Kwh	0.06911	0.06902	(0.00009)	(0.13)
Primary	$ /Kwh	0.06463	0.06454	(0.00009)	(0.14)
Transmission	$ /Kwh	0.06269	0.06261	(0.00008)	(0.13)
Semi-Peak Energy: Winter					
Secondary	$ /Kwh	0.04359	0.04353	(0.00006)	(0.14)
Primary	$ /Kwh	0.04047	0.04042	(0.00005)	(0.12)
Transmission	$ /Kwh	0.03925	0.03920	(0.00005)	(0.13)
Off-Peak Energy: Winter					
Secondary	$ /Kwh	0.03668	0.03663	(0.00005)	(0.14)
Primary	$ /Kwh	0.03337	0.03332	(0.00005)	(0.15)
Transmission	$ /Kwh	0.03237	0.03233	(0.00004)	(0.12)
SCHEDULE AL-TOU (Optional Times)					
Service Charge	$ /Month	30.00	30.00	0.00	0.00
On-Peak Rate Limiter: Summer	$ /Kwh	0.74	0.74	0.00	0.00
On-Peak Rate Limiter: Winter	$ /Kwh	0.29	0.29	0.00	0.00
Average Rate Limiter	$ /Kwh	5.00	5.00	0.00	0.00
Non-Coincident Demand					
Secondary	$ /KW	3.71	3.70	(0.01)	(0.27)
Primary	$ /KW	2.95	2.95	0.00	0.00
Transmission	$ /KW	1.24	1.24	0.00	0.00
On-Peak Demand: Summer					
Secondary	$ /KW	19.70	19.67	(0.03)	(0.15)
Primary	$ /KW	19.70	19.67	(0.03)	(0.15)
Transmission	$ /KW	12.39	12.37	(0.02)	(0.16)
On-Peak Demand: Winter					
Secondary	$ /KW	4.08	4.07	(0.01)	(0.25)
Primary	$ /KW	4.08	4.07	(0.01)	(0.25)
Transmission	$ /KW	1.64	1.64	0.00	0.00
On-Peak Energy: Summer					
Secondary	$ /Kwh	0.08656	0.08645	(0.00011)	(0.13)
Primary	$ /Kwh	0.08098	0.08088	(0.00010)	(0.12)
Transmission	$ /Kwh	0.07856	0.07845	(0.00011)	(0.14)
Semi-Peak Energy: Summer					
Secondary	$ /Kwh	0.05597	0.05590	(0.00007)	(0.13)
Primary	$ /Kwh	0.05332	0.05324	(0.00008)	(0.15)
Transmission	$ /Kwh	0.05172	0.05165	(0.00007)	(0.14)
Off-Peak Energy: Summer					
Secondary	$ /Kwh	0.03770	0.03765	(0.00005)	(0.13)
Primary	$ /Kwh	0.03528	0.03523	(0.00005)	(0.14)
Transmission	$ /Kwh	0.03423	0.03418	(0.00005)	(0.15)
On-Peak Energy: Winter					
Secondary	$ /Kwh	0.06911	0.06902	(0.00009)	(0.13)
Primary	$ /Kwh	0.06463	0.06454	(0.00009)	(0.14)
Transmission	$ /Kwh	0.06269	0.06261	(0.00008)	(0.13)
Semi-Peak Energy: Winter					
Secondary	$ /Kwh	0.04359	0.04353	(0.00006)	(0.14)
Primary	$ /Kwh	0.04047	0.04042	(0.00005)	(0.12)
Transmission	$ /Kwh	0.03925	0.03920	(0.00005)	(0.13)

DESCRIPTION (A)	UNITS (B)	9/2/92 PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	% (F)
Off-Peak Energy: Winter					
Secondary	$ /Kwh	0.03668	0.03663	(0.00005)	(0.14)
Primary	$ /Kwh	0.03337	0.03332	(0.00005)	(0.15)
Transmission	$ /Kwh	0.03237	0.03233	(0.00004)	(0.12)
SCHEDULE A6-TOU (Default Times)					
Service Charge	$ /Month	600.00	600.00	0.00	0.00
On-Peak Rate Limiter: Summer	$ /Kwh	0.74	0.74	0.00	0.00
On-Peak Rate Limiter: Winter	$ /Kwh	0.29	0.29	0.00	0.00
Average Rate Limiter	$ /Kwh	5	5.00	0.00	0.00
Non-Coincident Demand					
Primary	$ /KW	2.95	2.95	0.00	0.00
Transmission	$ /KW	1.24	1.24	0.00	0.00
On-Peak Demand: Summer					
Primary	$ /KW	20.89	20.86	(0.03)	(0.14)
Transmission	$ /KW	13.39	13.37	(0.02)	(0.15)
On-Peak Demand: Winter					
Primary	$ /KW	4.88	4.87	(0.01)	(0.20)
Transmission	$ /KW	2.17	2.17	0.00	0.00
On-Peak Energy: Summer					
Primary	$ /Kwh	0.07211	0.07201	(0.00010)	(0.14)
Transmission	$ /Kwh	0.06995	0.06986	(0.00009)	(0.13)
Semi-Peak Energy: Summer					
Primary	$ /Kwh	0.04747	0.04741	(0.00006)	(0.13)
Transmission	$ /Kwh	0.04605	0.04599	(0.00006)	(0.13)
Off-Peak Energy: Summer					
Primary	$ /Kwh	0.03528	0.03523	(0.00005)	(0.14)
Transmission	$ /Kwh	0.03423	0.03418	(0.00005)	(0.15)
On-Peak Energy: Winter					
Primary	$ /Kwh	0.06463	0.06454	(0.00009)	(0.14)
Transmission	$ /Kwh	0.06269	0.06261	(0.00008)	(0.13)
Semi-Peak Energy: Winter					
Primary	$ /Kwh	0.04047	0.04042	(0.00005)	(0.12)
Transmission	$ /Kwh	0.03925	0.03920	(0.00005)	(0.13)
Off-Peak Energy: Winter					
Primary	$ /Kwh	0.03337	0.03332	(0.00005)	(0.15)
Transmission	$ /Kwh	0.03237	0.03233	(0.00004)	(0.12)
SCHEDULE A6-TOU (Optional Times)					
Service Charge	$ /Month	600.00	600.00	0.00	0.00
On-Peak Rate Limiter: Summer	$ /Kwh	0.74	0.74	0.00	0.00
On-Peak Rate Limiter: Winter	$ /Kwh	0.29	0.29	0.00	0.00
Average Rate Limiter	$ /Kwh	5	5.00	0.00	0.00
Non-Coincident Demand					
Primary	$ /KW	2.95	2.95	0.00	0.00
Transmission	$ /KW	1.24	1.24	0.00	0.00
On-Peak Demand: Summer					
Primary	$ /KW	23.46	23.43	(0.03)	(0.13)
Transmission	$ /KW	15.04	15.02	(0.02)	(0.13)
On-Peak Demand: Winter					

DESCRIPTION (A)	UNITS (B)	9/2/92 PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	% (F)
Primary	$ /KW	4.88	4.87	(0.01)	(0.20)
Transmission	$ /KW	2.17	2.17	0.00	0.00
On-Peak Energy: Summer					
Primary	$ /Kwh	0.08098	0.08088	(0.00010)	(0.12)
Transmission	$ /Kwh	0.07856	0.07845	(0.00011)	(0.14)
Semi-Peak Energy: Summer					
Primary	$ /Kwh	0.05332	0.05324	(0.00008)	(0.15)
Transmission	$ /Kwh	0.05172	0.05165	(0.00007)	(0.14)
Off-Peak Energy: Summer					
Primary	$ /Kwh	0.03528	0.03523	(0.00005)	(0.14)
Transmission	$ /Kwh	0.03423	0.03418	(0.00005)	(0.15)
On-Peak Energy: Winter					
Primary	$ /Kwh	0.06463	0.06454	(0.00009)	(0.14)
Transmission	$ /Kwh	0.06269	0.06261	(0.00008)	(0.13)
Semi-Peak Energy: Winter					
Primary	$ /Kwh	0.04047	0.04042	(0.00005)	(0.12)
Transmission	$ /Kwh	0.03925	0.03920	(0.00005)	(0.13)
Off-Peak Energy: Winter					
Primary	$ /Kwh	0.03337	0.03332	(0.00005)	(0.15)
Transmission	$ /Kwh	0.03237	0.03233	(0.00004)	(0.12)
SCHEDULE AO-TOU					
Customer Charge	$ /Month	50.00	50.00	0.00	0.00
Non-Coincident Demand	$ /KW	8.82	8.82	(0.00)	(0.03)
On-Peak Demand: Summer	$ /KW	15.67	15.67	(0.00)	(0.03)
On-Peak Demand: Winter	$ /KW	4.22	4.22	(0.00)	(0.03)
Energy: On-Peak	$ /Kwh	0.04149	0.04148	(0.00001)	(0.03)
Energy: Semi-Peak	$ /Kwh	0.03471	0.03470	(0.00001)	(0.03)
Energy: Off-Peak	$ /Kwh	0.03101	0.03100	(0.00001)	(0.03)
SCHEDULE AO6-TOU					
Customer Charge	$ /Month	250.00	250.00	0.00	0.00
Non-Coincident Demand	$ /KW	8.82	8.82	(0.00)	(0.03)
On-Peak Demand: Summer	$ /KW	18.67	18.66	(0.01)	(0.03)
On-Peak Demand: Winter	$ /KW	5.03	5.03	(0.00)	(0.03)
Energy: On-Peak	$ /Kwh	0.04149	0.04148	(0.00001)	(0.03)
Energy: Semi-Peak	$ /Kwh	0.03471	0.03470	(0.00001)	(0.03)
Energy: Off-Peak	$ /Kwh	0.03101	0.03100	(0.00001)	(0.03)
SCHEDULE AY-TOU					
Service Charge	$ /Month	30.00	30.00	0.00	0.00
On-Peak Rate Limiter	$ /Kwh	0.48	0.48	0.00	0.00
Average Rate Limiter	$ /Kwh	5.00	5.00	0.00	0.00
Non-Coincident Demand					
Secondary	$ /KW	3.71	3.70	(0.01)	(0.27)
Primary	$ /KW	2.95	2.95	0.00	0.00
Transmission	$ /KW	1.24	1.24	0.00	0.00
On-Peak Demand					
Secondary	$ /KW	10.21	10.30	0.09	0.85
Primary	$ /KW	10.21	10.30	0.09	0.85

DESCRIPTION (A)	UNITS (B)	9/2/92 PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	% (F)
Transmission	$ /KW	5.85	5.90	0.05	0.85
On-Peak Energy					
Secondary	$ /Kwh	0.07520	0.07516	(0.00004)	(0.05)
Primary	$ /Kwh	0.07014	0.07009	(0.00005)	(0.07)
Transmission	$ /Kwh	0.06826	0.06818	(0.00008)	(0.12)
Semi-Peak Energy					
Secondary	$ /Kwh	0.04632	0.04630	(0.00002)	(0.04)
Primary	$ /Kwh	0.04343	0.04340	(0.00003)	(0.07)
Transmission	$ /Kwh	0.04277	0.04272	(0.00005)	(0.13)
Off-Peak Energy					
Secondary	$ /Kwh	0.03760	0.03756	(0.00004)	(0.11)
Primary	$ /Kwh	0.03461	0.03457	(0.00004)	(0.10)
Transmission	$ /Kwh	0.03372	0.03368	(0.00004)	(0.11)
SCHEDULE A-E2					
Customer Charge	$ /Month	600.00	600.00	0.00	0.00
Contract Demand	$ /KW	10.46	10.48	0.02	0.19
Non-Coincident Demand					
Secondary	$ /KW	3.71	3.70	(0.01)	(0.27)
Primary	$ /KW	2.95	2.95	0.00	0.00
Transmission	$ /KW	1.24	1.24	0.00	0.00
Energy: On-Peak	$ /Kwh	4.44476	4.45659	0.01183	0.27
Energy: Semi-Peak	$ /Kwh	0.06684	0.06702	0.00018	0.27
Energy: Off-Peak	$ /Kwh	0.03255	0.03264	0.00009	0.28
SCHEDULE R-TOU-3					
Customer Charge	$ /Month	600.00	600.00	0.00	0.00
Contract Demand	$ /KW	10.46	10.48	0.02	0.19
Non-Coincident Demand					
Secondary	$ /KW	3.71	3.70	(0.01)	(0.27)
Primary	$ /KW	2.95	2.95	0.00	0.00
Transmission	$ /KW	1.24	1.24	0.00	0.00
Energy: Super-Peak	$ /Kwh	1.26148	1.26483	0.00335	0.27
Energy: On-Peak	$ /Kwh	0.10203	0.10230	0.00027	0.27
Energy: Semi-Peak	$ /Kwh	0.04880	0.04893	0.00013	0.27
Energy: Off-Peak	$ /Kwh	0.03255	0.03264	0.00009	0.28
SCHEDULE R-TOU-4					
Customer Charge	$ /Month	600.00	600.00	0.00	0.00
Contract Demand	$ /KW	10.46	10.48	0.02	0.19
Non-Coincident Demand					
Secondary	$ /KW	3.71	3.70	(0.01)	(0.27)
Primary	$ /KW	2.95	2.95	0.00	0.00
Transmission	$ /KW	1.24	1.24	0.00	0.00
Energy: Super-Peak	$ /Kwh	0.49347	0.49479	0.00132	0.27
Energy: On-Peak	$ /Kwh	0.08155	0.08177	0.00022	0.27
Energy: Semi-Peak	$ /Kwh	0.04401	0.04413	0.00012	0.27
Energy: Off-Peak	$ /Kwh	0.03255	0.03264	0.00009	0.28
SCHEDULE S					

DESCRIPTION (A)	UNITS (B)	9/2/92 PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	% (F)
Contracted Demand					
Secondary	$ /Kwh	2.97	2.96	(0.01)	(0.27)
Primary	$ /Kwh	2.36	2.36	0.00	0.00
Transmission	$ /Kwh	0.99	0.99	0.00	0.00
SCHEDULE I-1					
Rate A: Utility Control	$ /kW	3.43	3.43	0.00	0.00
Rate B: Customer Control	$ /kW	2.29	2.29	0.00	0.00
Rate C					
Utility Control	$ /kW	3.43	3.43	0.00	0.00
Customer Control	$ /kW	2.29	2.29	0.00	0.00
SCHEDULE I-2					
Rate A: 1 YR Cancellation					
Guaranteed Load Credit	$ /kW	5.60	5.60	0.00	0.00
Rate A: 5 YR Cancellation					
Guaranteed Load Credit	$ /kW	7.06	7.06	0.00	0.00
Rate B: 1 YR Cancellation					
Guaranteed Load Credit	$ /kW	5.15	5.15	0.00	0.00
Rate B: 5 YR Cancellation					
Guaranteed Load Credit	$ /kW	6.47	6.47	0.00	0.00
Rate C: 1 YR Cancellation					
Guaranteed Load Credit	$ /kW	4.15	4.15	0.00	0.00
Rate C: 5 YR Cancellation					
Guaranteed Load Credit	$ /kW	5.24	5.24	0.00	0.00
Rate D: 1 YR Cancellation					
Guaranteed Load Credit	$ /kW	3.80	3.80	0.00	0.00
Rate D: YR Cancellation					
Guaranteed Load Credit	$ /kW	4.80	4.80	0.00	0.00
Rates A-D:					
Credit for Each Interruption	$ /kW	0.28	0.28	0.00	0.00
SCHEDULE I-3					
Rate A: 1 YR Cancellation					
Guaranteed Load Credit	$ /kW	5.60	5.60	0.00	0.00
Rate A: 5 YR Cancellation					
Guaranteed Load Credit	$ /kW	7.06	7.06	0.00	0.00
Rate B: 1 YR Cancellation					
Guaranteed Load Credit	$ /kW	5.15	5.15	0.00	0.00
Rate B: 5 YR Cancellation					
Guaranteed Load Credit	$ /kW	6.47	6.47	0.00	0.00
Rate C: 1 YR Cancellation					
Guaranteed Load Credit	$ /kW	4.15	4.15	0.00	0.00
Rate C: 5 YR Cancellation					
Guaranteed Load Credit	$ /kW	5.24	5.24	0.00	0.00
Rate D: 1 YR Cancellation					
Guaranteed Load Credit	$ /kW	3.80	3.80	0.00	0.00
Rate D: YR Cancellation					
Guaranteed Load Credit	$ /kW	4.80	4.80	0.00	0.00
Rates A-D:					
Credit for Each Interruption	$ /kW	0.28	0.28	0.00	0.00

DESCRIPTION (A)	UNITS (B)	9/2/92 PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	% (F)
SCHEDULE LR					
Customer Charge	$ /kW	150.00	150.00	0.00	0.00
Contract Min Load Reduction					
Demand Credit:					
Option 1	$ /kW	5.73	5.73	0.00	0.00
Option 2	$ /kW	4.30	4.30	0.00	0.00
Energy Credit for Output					
Over Contract					
Option 1	$ /kWh	0.85917	0.85917	0.00000	0.00
Option 2	$ /kWh	0.64438	0.64438	0.00000	0.00
Energy Credit for Output					
Under Contract					
Option 1	$ /kWh	13. 74675	13. 74675	0.00000	0.00
Option 2	$ /kWh	10. 31006	10. 31006	0.00000	0.00

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Note: A-E1 was eliminated 1/1/92.

SUMMARY OF AGRICULTURAL RATES

DESCRIPTION (A)	UNITS (B)	9/2/92 PRESENT RATE (C)	ADOPTED RATE (D)	CHANGE AMOUNT (E)	% (F)
SCHEDULE PA					
Customer Charge	$ /Month	8.00	8.00	0.00	0.00
Energy	$ /Kwh	0.08916	0.08980	0.00064	0.72
SCHEDULE PA-TOU					
Metering Charge	$ /Month	10.00	10.00	0.00	0.00
Customer Charge	$ /Month	8.00	8.00	0.00	0.00
Energy: On-Peak	$ /Kwh	0.16937	0.17069	0.00132	0.78
Energy: Off-Peak	$ /Kwh	0.07073	0.07128	0.00055	0.78
SCHEDULE PA-T-1					
Customer Charge	$ /Month	30.00	30.00	0.00	0.00
Demand: On-Peak					
Option A	$ /KW	11.53	11.51	(0.02)	(0.17)
Option B	$ /KW	10.13	10.11	(0.02)	(0.20)
Option C	$ /KW	9.92	9.90	(0.02)	(0.20)
Option D	$ /KW	10.33	10.31	(0.02)	(0.19)
Option E	$ /KW	10.12	10.10	(0.02)	(0.20)
Option F	$ /KW	9.69	9.67	(0.02)	(0.21)
Demand: Semi-Peak	$ /KW	0.50	0.50	0.00	0.00
Energy: On-Peak	$ /Kwh	0.09179	0.08807	(0.00372)	(4.05)
Energy: Semi-Peak	$ /Kwh	0.06725	0.06308	(0.00417)	(6.20)
Energy: Off-Peak	$ /Kwh	0.04287	0.03824	(0.00463)	(10.80)

SUMMARY [*292] OF STREETLIGHT RATES

DESCRIPTION WATTS (A)	LUMENS (B)	9/2/92 RATE ($ /Lamp) (C)	1/1/93 RATE ($ /Lamp) (D)	CHANGE ($ /Lamp) (E)	% (F)
LS-1, Mercury Vapor, Class A					
175	7,000	9.84	9.98	0.14	1.42
250	10,000	13.01	13.21	0.20	1.54
400	20,000	17.74	18.04	0.30	1.69
700	35,000	33.60	34.33	0.73	2.17
LS-1, Mercury Vapor, Class C, 1-Lamp					
175	7,000	18.49	18.63	0.14	0.76
250	10,000	24.52	24.72	0.20	0.82
400	20,000	29.25	29.56	0.31	1.06
LS-1, Mercury Vapor, Class C, 2-Lamp					
175	7,000	28.06	28.35	0.29	1.03
400	20,000	47.58	48.20	0.62	1.30
LS-1, HPSV, Class A					
70	5,800	6.45	6.52	0.07	1.09
100	9,500	7.44	7.54	0.10	1.34
150	16,000	8.79	8.92	0.13	1.48
200	22,000	10.56	10.73	0.17	1.61
250	30,000	13.32	13.52	0.20	1.50
400	50,000	16.55	16.87	0.32	1.93
1,000	140,000	34.35	35.08	0.73	2.13
LS-1, HPSV, Class B, 1-Lamp					
70	5,800	7.14	7.21	0.07	0.98
100	9,500	8.13	8.22	0.09	1.11
150	16,000	9.48	9.61	0.13	1.37
200	22,000	11.44	11.60	0.16	1.40
250	30,000	14.20	14.41	0.21	1.48
400	50,000	17.53	17.84	0.31	1.77
1,000	140,000	35.41	36.14	0.73	2.06
LS-1, HPSV, Class B, 2-Lamp					
70	5,800	12.40	12.54	0.14	1.13
100	9,500	14.38	14.57	0.19	1.32
150	16,000	17.08	17.34	0.26	1.52
200	22,000	20.86	21.19	0.33	1.58
250	30,000	26.38	26.80	0.42	1.59
400	50,000	32.77	33.41	0.64	1.95
1,000	140,000	68.50	69.96	1.46	2.13
LS-1, HPSV, Class C, 1-Lamp					
70	5,800	15.10	15.17	0.07	0.46
100	9,500	16.09	16.19	0.10	0.62
150	16,000	17.45	17.59	0.14	0.80
200	22,000	22.06	22.23	0.17	0.77
250	30,000	24.82	25.04	0.22	0.89
400	50,000	29.51	29.84	0.33	1.12
1,000	140,000	48.29	49.03	0.74	1.53
LS-1, HPSV, Class C, 2-Lamp					
70	5,800	21.28	21.42	0.14	0.66
100	9,500	23.26	23.45	0.19	0.82
150	16,000	25.97	26.24	0.27	1.04

DESCRIPTION WATTS (A)	LUMENS (B)	9/2/92 RATE ($ /Lamp) (C)	1/1/93 RATE ($ /Lamp) (D)	CHANGE ($ /Lamp) (E)	% (F)
200	22,000	33.20	33.54	0.34	1.02
250	30,000	38.72	39.15	0.43	1.11
400	50,000	44.11	44.75	0.64	1.45
1,000	140,000	81.14	82.61	1.47	1.81
LS-1, LPSV, Class A					
35	4,800	7.94	7.99	0.05	0.63
55	8,000	8.57	8.63	0.06	0.70
90	13,500	10.54	10.64	0.10	0.95
135	22,500	12.99	13.12	0.13	1.00
180	33,000	14.10	14.25	0.15	1.06
LS-1, LPSV, Class B, 1-Lamp					
35	4,800	8.64	8.68	0.04	0.46
55	8,000	9.37	9.43	0.06	0.64
90	13,500	11.34	11.44	0.10	0.88
135	22,500	13.98	14.12	0.14	1.00
180	33,000	15.09	15.25	0.16	1.06
LS-1, LPSV, Class B, 2-Lamp					
35	4,800	15.39	15.48	0.09	0.58
55	8,000	16.75	16.87	0.12	0.72
90	13,500	20.69	20.89	0.20	0.97
135	22,500	25.84	26.12	0.28	1.08
180	33,000	28.07	28.38	0.31	1.10
LS-1, LPSV, Class C, 1-Lamp					
35	4,800	16.59	16.65	0.06	0.36
55	8,000	17.33	17.40	0.07	0.40
90	13,500	19.32	19.42	0.10	0.52
135	22,500	24.61	24.75	0.14	0.57
180	33,000	25.72	25.88	0.16	0.62
LS-1, LPSV, Class C, 2-Lamp					
35	4,800	24.27	24.37	0.10	0.41
55	8,000	25.63	25.76	0.13	0.51
90	13,500	29.59	29.79	0.20	0.68
135	22,500	38.18	38.47	0.29	0.76
180	33,000	40.41	40.73	0.32	0.79
LS-1, Facilities and Rates, Class A					
Center Suspension	4.77	4.78	0.01	0.21	
Non-Standard Wood Pole					
30-foot	2.39	2.40	0.01	0.42	
35-foot	2.69	2.69	0.00	0.00	
Reactor Ballast Discount					
175	(0.97)	(0.98)	(0.01)	(1.03)	
250	(0.38)	(0.38)	0.00	0.00	
LS-2, Mercury Vapor, Rate A					
175	7,000	5.07	5.20	0.13	2.56
250	10,000	7.05	7.24	0.19	2.70
400	20,000	11.10	11.40	0.30	2.70
700	35,000	18.82	19.33	0.51	2.71
1,000	55,000	26.59	27.31	0.72	2.71
LS-2, Mercury Vapor, Rate B, Energy & Limited Maintenance					

DESCRIPTION WATTS (A)	LUMENS (B)	9/2/92 RATE ($ /Lamp) (C)	1/1/93 RATE ($ /Lamp) (D)	CHANGE ($ /Lamp) (E)	% (F)
175	7,000	5.67	5.81	0.14	2.47
250	10,000	7.65	7.84	0.19	2.48
400	20,000	11.71	12.01	0.30	2.56
LS-2, Mercury Vapor, Surcharge for series service					
175	7,000	0.40	0.40	0.00	0.00
250	10,000	0.50	0.50	0.00	0.00
400	20,000	0.72	0.72	0.00	0.00
700	35,000	1.32	1.32	0.00	0.00
LS-2, HPSV, Rate A					
50	3,300	1.40	1.44	0.04	2.86
70	5,800	2.44	2.50	0.06	2.46
100	9,500	3.40	3.49	0.09	2.65
150	16,000	4.66	4.78	0.12	2.58
200	22,000	5.94	6.10	0.16	2.69
250	30,000	7.55	7.76	0.21	2.78
310	37,000	9.24	9.49	0.25	2.71
400	50,000	11.49	11.80	0.31	2.70
1,000	140,000	26.59	27.31	0.72	2.71
LS-2, HPSV, Rate B, Energy & Limited Maintenance					
50	3,300	2.08	2.12	0.04	1.92
70	5,800	3.11	3.18	0.07	2.25
100	9,500	4.08	4.17	0.09	2.21
150	16,000	5.35	5.48	0.13	2.43
200	22,000	6.63	6.79	0.16	2.41
250	30,000	8.24	8.45	0.21	2.55
310	37,000	9.94	10.20	0.26	2.62
400	50,000	12.19	12.50	0.31	2.54
1,000	140,000	27.45	28.17	0.72	2.62
LS-2, HPSV, Reduction for 120-volt Reactor Ballast					
70	5,800	(0.40)	(0.40)	0.00	0.00
100	9,500	(0.53)	(0.53)	0.00	0.00
150	16,000	(0.49)	(0.49)	0.00	0.00
LS-2, HPSV, Surcharge for Series Service					
50	3,300	0.45	0.45	0.00	0.00
70	5,800	(0.22)	(0.22)	0.00	0.00
100	9,500	(0.23)	(0.23)	0.00	0.00
150	16,000	0.02	0.02	0.00	0.00
200	22,000	0.47	0.48	0.01	2.13
LS-2, LPSV, Rate A					
35	4,800	1.57	1.61	0.04	2.55
55	8,000	2.06	2.12	0.06	2.91
90	13,500	3.40	3.49	0.09	2.65
135	22,500	4.83	4.96	0.13	2.69
180	33,000	5.51	5.65	0.14	2.54
LS-2, LPSV, Surcharge for series service					
35	4,800	(0.23)	(0.23)	0.00	0.00
55	8,000	(0.13)	(0.13)	0.00	0.00
90	13,500	0.45	0.45	0.00	0.00
135	22,500	0.80	0.80	0.00	0.00
180	33,000	0.51	0.51	0.00	0.00

		9/2/92	1/1/93	CHANGE	
DESCRIPTION		RATE	RATE		
WATTS	LUMENS	($ /Lamp)	($ /Lamp)	($ /Lamp)	%
(A)	(B)	(C)	(D)	(E)	(F)
LS-2, Incandescent Lamps, Rate A, Energy Only					
	1,000	1.71	1.76	0.05	2.92
	2,500	3.80	3.90	0.10	2.63
	4,000	5.72	5.87	0.15	2.62
	6,000	8.39	8.61	0.22	2.62
	10,000	14.24	14.63	0.39	2.74
LS-2, Incdsnt Lamps, Rate B, Energy and Limited Maintenance					
	4,000	7.67	7.83	0.16	2.09
	6,000	10.39	10.62	0.23	2.21
LS-3					
Energy Charge ($ /kwh)		0.07376	0.08014	0.01	8.65
Min Charge ($ /month)		5.81	5.81	0.00	0.00
OL-1, Mercury Vapor, Rate A, St Light Luminaire					
175	7,000	9.72	9.85	0.13	1.34
400	20,000	19.59	19.90	0.31	1.58
OL-1, HPSV, Rate A, Street Light Luminaire					
100	9,500	8.23	8.33	0.10	1.22
150	16,000	9.60	9.73	0.13	1.35
250	30,000	14.61	14.82	0.21	1.44
400	50,000	17.58	17.89	0.31	1.76
1,000	140,000	36.05	36.78	0.73	2.02
OL-1, HPSV, Rate B, Directional Luminaire					
250	30,000	17.25	17.99	0.74	4.29
400	50,000	21.13	22.27	1.14	5.40
1,000	140,000	36.81	39.38	2.57	6.98
OL-1, LPSV, Rate A, Street Light Luminaire					
55	8,000	8.68	8.74	0.06	0.69
90	13,000	10.67	10.77	0.10	0.94
135	22,500	13.15	13.29	0.14	1.06
180	33,000	14.27	14.43	0.16	1.12
OL-1, Pole					
30 ft wood pole	3.15	3.16	0.01	0.32	
35 ft wood pole	3.54	3.55	0.01	0.28	
DWL, facilities Charges					
$ of Util invst.	0.0186	0.0186	0.00	0.00	
DWL, Energy and Lamp Maintenance Charge					
50 Watt HPSV	3.16	3.20	0.04	1.27	
DWL, Min. Charge	151.14	151.55	0.41	0.27	

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APPENDIX L

SAN DIEGO GAS AND ELECTRIC

1993 GENERAL RATE CASE

(Gas Department)

Forecast Period: January 1 through December 31, 1992

SUMMARY OF CHANGES IN REVENUE REQUIREMENTS

BASE RATE REVENUES			
BASE REVENUES:	PRESENT REV.	REV. CHANGE	ADOPTED REV.
Sales to Customers	$ 147,579	$ 13,941	$ 161,520
Interdepartmental	$ 10,171	$ 1,730	$ 11,901
Total Base Revenues	$ 157,750	$ 15,671	$ 173,421
Additional Margin Costs			
DSM Collaborative (10/91-12/91)	$ 507	$ 0	$ 507
1990 DSM Reward (1992 Recovery)	$ 1,959	($ 1,959)	$ 0
1991 DSM Reward (1993 Recovery)	$ 0	$ 290	$ 297
Jan-March Margin Interest	$ 2,520	($ 2,520)	$ 0
DSM Balancing Acct. Amortization	$ 0	$ 2,296	$ 2,296
Subtotal SDG&E Margin Costs	$ 162,736	$ 13,785	$ 176,521
Sales adjustment	($ 36)	$ 36	$ 0
Net SDG&E Margin Cost Recovery	$ 162,700	$ 13,821	$ 176,521
ADJUSTMENTS TO GAS MARGIN TO BE RECOVERED IN RATES:			
Net SDG&E Gas Margin	$ 162,700	$ 13,821	$ 176,521
Low Income Rate Assistance (LIRA)	($ 2,329)	$ 0	($ 2,329)
Balancing Account Amortizations	$ 11,047	($ 3,452)	$ 7,595
SoCalGas Fixed Costs	$ 80,681	$ 0	$ 80,681
Other Transmission Costs	$ 4,618	$ 0	$ 4,618
TOTAL BASE RATE REVENUES	$ 256,717	$ 10,369	$ 267,086
PROCUREMENT REV. REQ.	$ 217,002	$ 0	$ 217,002
SUBTOTAL ADOPTED REVS.	$ 473,719	$ 10,369	$ 484,088
Miscellaneous	$ 3,152	($ 348)	$ 2,804
TOTAL GAS DEPT. REV.	$ 476,871	$ 10,021	$ 486,892

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GAS REVENUE ALLOCATION SUMMARY

CUSTOMER GROUP	ADOPTED SALES	PRESENT REVENUES	PRESENT AVE. RATE	ADOPTED REVENUES

	A (Mtherms)	B ($ 000)	C (C/therm)	D ($ 000)
1 CORE				
2 Residential	338,191	$ 201,923	59.707	$ 208,066
3 Commercial	117,640	$ 68,848	58.524	$ 70,943
4 TOTAL CORE	455,831	$ 270,771	59.402	$ 279,009
5 NONCORE				
6 Comml/Industrial	61,163	$ 22,681	37.082	$ 23,148
7 Cogeneration	174,000	$ 50,582	29.070	$ 51,927
8 Subtotal	235,163	$ 73,262	31.154	$ 75,075
5 UEG	384,106	$ 129,686	33.763	$ 130,004
6 TOTAL NONCORE	619,269	$ 202,948	32.772	$ 205,079
7 RATE RECOVERY	1,075,100	$ 473,719	44.063	$ 484,088
8 MISC. REVENUES		$ 3,152		$ 2,804
9 REV REQUIREMENTS	1,075,100	$ 476,871		$ 486,892

CUSTOMER GROUP	ADOPTED AVE. RATE E (C/therm)	REVENUE CHANGE F ($ 000)	RATE CHANGE G (C/therm)	RATE CHANGE H (%)
1 CORE				
2 Residential	61.523	$ 6,142	1.816	3.04%
3 Commercial	60.305	$ 2,096	1.781	3.04%
4 TOTAL CORE	61.209	$ 8,238	1.807	3.04%
5 NONCORE				
6 Comml/Industrial	37.846	$ 467	0.764	2.06%
7 Cogeneration	29.843	$ 1,346	0.773	2.66%
8 Subtotal	31.925	$ 1,813	0.771	2.47%
5 UEG	33.846	$ 318	0.083	0.25%
6 TOTAL NONCORE	33.116	$ 2,131	0.344	1.05%
7 RATE RECOVERY	45.027	$ 10,369	0.964	2.19%
8 MISC. REVENUES		($ 348)		
9 REV REQUIREMENTS		$ 10,021		2.10%

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Notes:

1/ Lines 6 through 8 include transportation-only charges for self-procurement customers. As such, the average rates exclude the purchase price of transport-only customers.

ADOPTED SALES FORECAST

Customer Group	1993 GRC A (Mtherms)	1992BCAP B (Mtherms)	GRC-BCAP C (Mtherms)	Change D C/B
1 CORE				
2 Residential	338,191	330,441	7,750	2.3%
3 Commercial	117,640	112,932	4,708	4.2%
4 TOTAL CORE	455,831	443,373	12,458	2.8%
5 NONCORE				
6 Comml/Industrial	61,163	67,608	(6,445)	-9.5%
7 Cogeneration	174,000	160,450	13,550	8.4%
8 RETAIL SUBTOTAL	690,994	671,431	19,563	2.9%
9 UEG	384,106	427,116	(43,010)	-10.1%
10 SYSTEM TOTALS	1,075,100	1,098,547	(23,447)	-2.1%

UNCAPPED GAS RATES SUMMARY

CUSTOMER GROUP	UNITS A	PRESENT RATES B	ADOPTED RATES C	RATE CHANGE D	% CHANGE E
1 RESIDENTIAL GR, GM, GS, & GT:					
2 Regular Baseline	C/therm	54.886	56.522	1.636	2.98%
3 Regular Non-Baseline	C/therm	74.041	76.248	2.207	2.98%
4 NBL/BL Difference	C/therm	19.155	19.726	0.571	2.98%
5 NBL/BL Ratio		1.35	1.35		
6 LIRA Baseline	C/therm	46.737	48.127	1.390	2.97%
7 LIRA Non-Baseline	C/therm	63.020	64.895	1.875	2.97%
8 GS Unit Discount	$ /month	($ 1.90)	($ 1.90)	0.000	0.00%
9 GT Unit Discount	$ /month	($ 6.00)	($ 6.00)	0.000	0.00%
10 RESIDENTIAL GL-1:					
11 Facility Charge	$ /month	14.310	14.310	0.000	0.00%
12 Volumetric Surcharge	C/therm	16.169	16.169	0.000	0.00%
13 CORE COMMERCIAL:					
14 GN-1 Service Charge	$ /month	$ 5.00	$ 5.00	0.000	0.00%
15 GN-2 Service Charge	$ /month	$ 60.00	$ 60.00	0.000	0.00%
16 Volumetric Charges:					

CUSTOMER GROUP	UNITS	PRESENT RATES	ADOPTED RATES	RATE CHANGE	% CHANGE
	A	B	C	D	E
17 Winter 0-3000 therms	C/therm	73.537	75.725	2.188	2.97%
18 All excess	C/therm	43.346	44.633	1.287	2.97%
	Ratio	1.70	1.70		
19 Summer 0-3000 therms	C/therm	62.318	64.178	1.860	2.99%
20 All excess	C/therm	42.344	43.608	1.264	2.99%
	Ratio	1.47	1.47		
21 NGV Bus Fleets	C/therm	50.000	50.000	0.000	0.00%
22 Other	C/therm	70.000	70.000	0.000	0.00%
23 Uncompressed	C/therm	35.000	35.000	0.000	0.00%
24 CORE PROCUREMENT PRICE	C/therm	19.399	19.399	0.000	0.00%
1 COMMERCIAL/INDUSTRIAL GTNC:					
2 Volumetric Charges - Winter	C/therm	18.069	18.932	0.863	4.77%
3 Volumetric Charges - Summer	C/therm	14.579	15.275	0.696	4.77%
	Ratio	1.239	1.239		
4 Customer Charges:					
5 0 to 3,000 therms	$ /month	$ 11	$ 11	$ 0	0.00%
6 3,001 to 7,000 therms	$ /month	$ 55	$ 55	$ 0	0.00%
7 7,001 to 23,000 therms	$ /month	$ 101	$ 101	$ 0	0.00%
8 23,001 to 126,000 therms	$ /month	$ 202	$ 202	$ 0	0.00%
9 126,001 to 1,000,000 therms	$ /month	$ 405	$ 405	$ 0	0.00%
10 Over 1,000,000	$ /month	$ 860	$ 860	$ 0	0.00%
11 Average Transmission Rate	C/therm	16.226	16.990	0.764	4.71%
12 COGENERATION GTCG:					
13 Volumetric Charges - Winter	C/therm	12.232	13.119	0.887	7.25%
14 Volumetric Charges - Summer	C/therm	9.752	10.459	0.707	7.25%
	Ratio	1.254	1.254		
15 Customer Charges:					
16 0 to 3,000 therms	$ /month	$ 15	$ 15	$ 0	0.00%
17 3,001 to 7,000 therms	$ /month	$ 82	$ 82	$ 0	0.00%
18 7,001 to 23,000 therms	$ /month	$ 150	$ 150	$ 0	0.00%
19 23,001 to 126,000 therms	$ /month	$ 300	$ 300	$ 0	0.00%
20 126,001 to 1,000,000 therms	$ /month	$ 600	$ 600	$ 0	0.00%
21 Over 1,000,000	$ /month	$ 1,274	$ 1,274	$ 0	0.00%
22 Average Transmission Rate	C/therm	10.817	11.591	0.773	7.15%
23 UTILITY ELECTRIC GENERATION, GTUEG:					
24 Demand Charges	$ 000/ month	$ 2,510	$ 2,528	$ 18	0.72%
25 Volumetric Charges -					

CUSTOMER GROUP		UNITS	PRESENT RATES	ADOPTED RATES	RATE CHANGE	% CHANGE
		A	B	C	D	E
Igniter Fuel		C/therm	41.862	42.165	0.303	0.72%
26	- Tier 1	C/therm	6.551	6.599	0.048	0.73%
27	- Tier 2	C/therm	2.869	2.890	0.021	0.73%
28 Average Transmission Rate		C/therm	11.508	11.591	0.083	0.72%

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APPENDIX M

SAN DIEGO GAS AND ELECTRIC COMPANY 1993 GRC
(STEAM DEPARTMENT)
FORECAST PERIOD: JANUARY 1, 1993 THROUGH DECEMBER 31, 1993
SUMMARY OF CHANGES IN BASE RATE REVENUE
($ 000)

	PRESENT REVENUE (A)	REVENUE CHANGES (B)	ADOPTED REVENUE (C)
BASE RATE REVENUES:			
- Authorized Margin (1/1/92)	$ 1,626	$ 0	$ 1,626
- 1993 General Rate Case	$ 0	($ 18)	($ 18)
- Proposed Subtotal	$ 1,626	($ 18)	$ 1,608
- Sales Adjustment n1	($ 101)	$ 101	$ 0
Subtotal Base Rate Revenue	$ 1,525	$ 83	$ 1,608
SRAM			
- Balancing	$ 448	$ 0	$ 448
TOTAL BASE RATE REVENUE	$ 1,973	$ 83	$ 2,056
ECAC:			
- Offset	$ 231	$ 0	$ 231
- Balancing	$ 11	$ 0	$ 11
TOTAL FOR STEAM DEPARTMENT	$ 2,215	$ 83	$ 2,298

n1 Sales Adjustment represents change in rate revenue recovery due to a reduction in sales, not a change in the authorized level of rate revenue.

SUMMARY OF STEAM RATES

DESCRIPTION (A)	BILLING UNITS (B)	PROPOSED RATE ($ /UNIT) (C)	REVENUE ($) (D)	TOTAL REVENUE ($) (E)
SCHEDULE 1				
Customer Charge	84	$ 250.000	$ 21,000	$ 21,000
Commodity Rate	25,805	$ 88.229	$ 2,276,737	$ 2,276,737
Subtotal				$ 2,297,737

DESCRIPTION (A)	BILLING UNITS (B)	PROPOSED RATE ($ /UNIT) (C)	REVENUE ($) (D)	TOTAL REVENUE ($) (E)
SCHEDULE 2				
Customer Charge	0	$ 252.500	$ 0	$ 0
Commodity Rate	0	$ 88.876	$ 0	$ 0
Subtotal				$ 2,297,737
ADOPTED TOTAL STEAM REVENUE				$ 2,297,737

[*297]

APPENDIX N

SETTLEMENT AGREEMENT

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Pursuant to the California Public Utilities Commission ("Commission") Rules of Practice and Procedure, Section 51.3 ("Rule 51.3"), the Commission's Division of Ratepayer Advocates ("DRA"), San Diego Gas & Electric Company ("SDG&E"), the Utility Consumers' Action Network ("UCAN"), and the City of San Diego, (collectively, the "Settling Parties") [*298] respectfully submit to the Commission this Settlement Agreement. In this Settlement Agreement, the Settling Parties provide to the Commission a recommended resolution of the vast majority of the issues that have been designated for consideration in Phase I of this proceeding, including the associated revenue requirement increase for Test Year 1993.

Certain topics are not resolved by this Settlement Agreement and will be litigated unless resolved by subsequent agreement. These unresolved matters include: Emerging Business Enterprise (Women/Minority Business Enterprise) costs, demand-side management program costs and incentive rewards, and certain affiliate issues raised in the DRA's Report on the Results of Examination. The issues designated for consideration in Phase II of this proceeding pertaining to cost of service, revenue allocation and rate design have not been addressed. Pursuant to the Rate Case Plan established in Decision No. 89-01-040, the cost of capital to be adopted for SDG&E's 1993 Test Year will be litigated and determined in a separate generic proceeding.

Accompanying this Settlement Agreement is the Joint Motion of the Settling Parties requesting that the Commission [*299] adopt the terms of this Settlement Agreement in its decision on Application No. 91-11-024.

I.

INTRODUCTION AND BACKGROUND

In its Decision No. 91-07-014 (July 2, 1991), the Commission authorized SDG&E to file a 1993 Test Year general rate case ("GRC"). That decision exempted SDG&E from the requirement to file a notice of intent and directed that SDG&E's GRC application be filed on November 15, 1991. In addition, the decision ordered two deviations from standard GRC application content. First, it directed resource plan issues that would ordinarily be considered in a GRC to be addressed in Order Instituting Investigation ("I") 89-07-004, the Biennial Resource Plan Update. Second, it ordered the 1993 Test Year electric sales forecast for SDG&E to be adopted from the sales forecast approved in SDG&E's Energy Cost Adjustment Clause proceeding applicable to the May 1, 1992 through April 30, 1993 forecast period.[22]

Pursuant to Decision No. 91-07-014, on November 15, 1991, SDG&E filed Application No. 91-11-024, which requested an increase in its authorized base rate revenues for electric, gas and steam [*300] service of $ 143.4 million to be effective for service rendered on and after January 1, 1993. Based on the sales forecast identified in SDG&E's application, this request would result in a $ 145.3 million rate increase. SDG&E's application includes 17 volumes of testimony, supported by several thousand pages of workpapers which were made available to DRA and other parties at the time of filing. On March 2, 1992, SDG&E distributed updated summary of earnings tables incorporating the effects of 1991 year-end Commission decisions. These tables express a reduction in SDG&E's total base rate revenue increase request to $ 140.3 million.

DRA's examination of an appropriate revenue level for SDG&E's 1993 Test Year began several months prior to the filing of SDG&E's application. Beginning on February 12, 1991, DRA issued to SDG&E a comprehensive master data request consisting of over 450 questions and requests for information. Following the filing of SDG&E's application, DRA continued its indepth examination, propounding over 1,345 additional questions and requests for information. These requests probed virtually every element of SDG&E's prepared testimony addressing Phase I issues. [*301] DRA also assigned two financial examiners who reviewed the financial, accounting and operating records of SDG&E in San Diego. The Settling Parties believe DRA's review of SDG&E's application and supporting materials was both extensive and complete.

UCAN's involvement in this case began prior to SDG&E's November, 1991 filing. Its active role in the proposed merger afforded UCAN insights into SDG&E's revenue needs and corporate policies which led to an active role in GRC discovery. UCAN's discovery included issuing eight separate data requests encompassing over 430 questions focused on SDG&E's proposed plant additions, administrative and general costs and corporate policies. It also investigated the utility's customer service and the alleged need for enhanced reliability. UCAN retained the consulting firm JBS Energy

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[22] This forecast was adopted in Decision 92-04-061, dated April 22, 1992.

to conduct in-depth analysis of SDG&E workpapers and calculations. JBS Energy staff also reviewed DRA's report and its conclusions.

The City of San Diego, as represented by the City Attorney's Office, has been an active participant in all aspects of this General Rate Case. The City of San Diego propounded three formal data requests containing 37 questions, in addition [*302] to extensive informal discovery. This discovery was focused primarily upon SDG&E's requested plant additions and operating and maintenance costs.

A prehearing conference was held on January 6, 1992 before the Assigned Commissioner, President Daniel Wm. Fessler, and Administrative Law Judges Steven A. Weissman and Thomas R. Pulsifer. At this conference, April 10, 1992 was established as the date for issuance of DRA's Phase I reports. In addition, SDG&E expressed its intention and desire to explore settlement opportunities following the issuance of DRA's reports and presented a schedule for processing its application in the event a settlement was reached. Through settlement SDG&E desired to achieve earlier certainty of outcome than would otherwise be possible, thereby freeing up parties' and Commission resources to be used productively in other proceedings and enabling SDG&E to get an early start on test year planning.

On April 10, 1992, DRA served its 11 volumes of testimony on the parties to this proceeding, including detailed reports on SDG&E's electric, gas and steam results of operations, and numerous other reports. In total, DRA's reports recommended that SDG&E's base rate [*303] revenue increase be limited to $ 44.8 million. SDG&E's application and DRA's reports, including appendices and exhibits, are incorporated herein by reference.

Based upon the positions expressed in SDG&E's application and DRA's subsequent reports, the Settling Parties perceived a potential to reach compromises on various issues. Accordingly, following the issuance of DRA's reports, the parties began intensive discussions of potential settlement positions. On April 23, 1993, SDG&E and DRA jointly issued to all parties a Notice of Settlement Conference to be convened on May 4, 1992 in San Diego.

A second prehearing conference was held before Administrative Law Judge Weissman on April 27, 1992. Following that prehearing conference, parties interested in revenue requirement issues continued their confidential discussions regarding potential settlement positions.

Consistent with the notice mailed to parties on April 23, 1992, a settlement conference was held on May 4, 1992 at 101 Ash Street, San Diego. At that settlement conference, parties held additional discussions on their respective positions and on tentative agreements that had been reached.

Other than SDG&E and DRA, only [*304] one party has filed testimony in this proceeding regarding the matters addressed in this Settlement Agreement. That party, the California Energy Commission, filed testimony on May 6, 1992, recommending that SDG&E receive additional funding to support two specific research programs.

Because of the timing of the signing of this Settlement Agreement, testimony that UCAN was preparing will not be introduced. Similarly, rebuttal testimony that SDG&E was preparing will not be introduced. The City of San Diego has not prepared testimony. The Settling Parties, in the course of negotiations, raised and considered many of the arguments that would have been set forth in intervenor testimony or SDG&E's rebuttal.

As compared to SDG&E's request for an increase of $ 140.3 million in base rate revenues, this Settlement Agreement results in an increase in base rate revenues of approximately $ 72.5 million. This Settlement Agreement presents the compromises reached by the Settling Parties. These parties urge the Commission to approve it as a fair and reasonable resolution of the issues.

II.

REASONABLENESS OF THE SETTLEMENT

The Settling Parties believe this Settlement Agreement complies with [*305] the Commission's requirements that settlements be reasonable, consistent with law, and clearly in the public interest. The compromises embodied in the Settlement Agreement reflect the Settling Parties' efforts to acknowledge the pressures placed on SDG&E by inflation and a growing customer base. At the same time, however, the Settling Parties have insisted that SDG&E demonstrate efficiency in its operations such that productivity achievements will offset a significant amount of the requirement for increased revenues. In addition, the Settling Parties have sought to reduce funding requests in light of continuing recessionary trends.

As indications that the Settlement Agreement reflects a reasonable and fair bottom line, the Settling Parties wish to have the Commission note the following facts:

1) The workpapers supporting SDG&E's filing include a fully developed Business Plan for 1993. The Business Plan contains specific programs, activities and projected expenses in support of the full amount of SDG&E's requested increase for 1993. In addition, SDG&E's Corporate Policy testimony in this case states eight corporate goals that SDG&E alleges will guide its conduct during the test [*306] period, including goals to improve customer service and to remain the low-cost provider of electric service among the state's investor-owned electric utilities. This Settlement Agreement does not endorse each of SDG&E's goals specifically, but the Settling

Parties commend SDG&E for this public commitment to such a set of corporate goals.

2) Productivity studies prepared by SDG&E and DRA[23] support the Settling Parties' conclusion that the level of revenues for SDG&E adopted in this Settlement Agreement reflects the achievement of substantial levels of productivity in the past, and will require SDG&E to achieve further productivity improvements during the test period in order to earn its authorized rate of return. Between 1988 (the base year utilized by SDG&E and DRA in this proceeding) and the beginning of the 1993 Test Year, SDG&E will have experienced an increase of approximately 99,000 customers, yet its employee population will be no higher in 1993 than it was in 1988. SDG&E now has the lowest electric rates of the state's investor-owned electric utilities, as compared to being the high cost provider in 1988, and will have virtually the same rates in 1993 as it did in 1988. [*307]

3) The Settling Parties have recognized that there is risk involved in litigation, and that no party was likely to be 100% successful in supporting its filed case. The Settling Parties have vigorously argued their positions in this matter, and have reached compromise positions that they believe are appropriate in light of the litigation risks. In the process of reaching these compromises, the Settling Parties in certain instances have considered some smaller issues in the aggregate rather than item by item. The Settling Parties believe that this approach was used appropriately given the multiplicity of issues addressed. The level of revenues agreed to in this Settlement Agreement reflects the Settling Parties' best judgments as to the totality of their positions and risks, and their agreement herein is explicitly based on the bottom line result achieved.

III.

SETTLEMENT AND STIPULATIONS

Appendix A to this Settlement Agreement contains four Summary of Earnings tables (Combined, Electric, Gas and Steam). These tables set forth the positions expressed in SDG&E's application, as [*308] revised on March 2, 1992, and in DRA's

[23] SDG&E's "Report on Productivity" (SDG&E-10); DRA's "Report on Total Factor Productivity."

reports, by FERC functional account area.[24] The final column on each table, labeled "Settlement", presents the levels of expense (by functional area), revenue and rate base agreed upon by the Settling Parties, subject to: 1) changes resulting from updated escalation rates, as further described in subparagraph III.A.2. below, 2) any change in SDG&E's authorized cost of capital for the 1993 Test Year, and 3) various other adjustments described in this Settlement Agreement.

In addition to the agreements expressed in the "Settlement" column on each Summary of Earnings table, the Settling Parties agree as follows:

A. OPERATIONS AND MAINTENANCE ("O&M") EXPENSE.

1. Authorized O&M Expense. The Settling Parties agree that the amount of O&M expenses that SDG&E should be allowed to recover in rates in the 1993 Test Year is $ 380.112 million. Of this amount, $ 305.903 million is allocable to electric service, $ 73.218 [*309] million is allocable to gas service, and $ .991 million is allocable to steam service.[25]

2. Forecast Methodology. Both SDG&E and DRA based their respective test year expense forecasts largely on analyses of historical data. In most instances the differences in their forecasts are the result of employing different forecast methodologies, such as: 1) trends, 2) averages, 3) zero-based estimating, 4) adjustments to recorded expenses, and 5) varying historical time periods. The Settling Parties agree that the proper application of forecast methodologies requires the use of judgment and that, as in any forecasting exercise, there is a range of reasonable outcomes. The Settling Parties also agree that different methodologies can produce results within this range and that no single methodology will produce the sole reasonable result in every instance.

The level of test year expenses recommended by the Settling Parties is based upon their individual judgments regarding the strengths and weaknesses of competing forecasting [*310] methodologies, and the resulting compromises each party felt were

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[24] All operations and maintenance expenses set forth in this Settlement Agreement are expressed in 1988 dollars unless otherwise specified. Capital-related costs reflect SDG&E's currently authorized rate of return (10.75%).

[25] As noted above, these amounts are subject to change due to updated escalation rates, a revised cost of capital and other adjustments specified below.

reasonable. Except as specifically identified in this Settlement Agreement, the substantial differences among the Settling Parties' initial positions in each major expense area were resolved through such judgments and compromises.

To the extent the Settling Parties have identified policy issues affecting test year expenses, such issues have been dealt with explicitly in this Settlement Agreement, left for litigation, or deferred to other Commission proceedings that may modify the test year revenue requirements.

3. Cost Escalation. The Settling Parties agree to use DRA's proposed escalation methodology, set forth in its "Report on the Results of Operations" (Electric), for escalating both labor and non-labor O&M expenses. The Settling Parties further agree that this methodology will be applied to the agreed upon O&M costs as set forth in subparagraph III.A.1 above, using third quarter 1992 DRI indices, for final determination of the allowed level of O&M expenses for escalation to 1993 dollars. The labor, non-labor and other expense allocations for purposes of escalating from 1988 dollars to 1993 dollars for [*311] electric, gas and steam are set forth in Appendix B hereto.

4. Franchise Fees and Uncollectibles. The franchise fees portion of O&M expense has been calculated using franchise fee rates of 1.93% for electric, 2.18% for gas and 2.10% for steam service. The uncollectibles portion of O&M expense has been calculated using a rate of .274% for the Electric and Gas Departments. These rates are acceptable to the Settling Parties. Because frnachise fees and uncollectibles are calculated based on total revenues, they are stated in 1993 dollars throughout the Settlement Agreement.

5. Electric Production.

a. Heber. The electric production expense agreed upon by the Settling Parties does not include the $ .6 million (1993$) requested by SDG&E for maintenance of the Heber Geothermal Binary Plant because the Commission in Resolution No. E-3236 (Oct. 23, 1991) has approved the sale of this plant.

b. Dredge. The Settling Parties agree that, in order to avoid the need for attrition year adjustments, the electric production dredge expenses should be collected over a three year period. Consequently, the revenue levels identified in the Settlement Agreement are expressly deemed [*312] to reflect a three year amortization of dredge costs.

c. Nuclear. The agreed upon level of electric production expense contemplates only one refueling outage for the San Onofre Nuclear Generating Station ("SONGS") units, of which SDG&E is a 20% owner. The Settling Parties recognize that the number of SONGS refuelings and the level of associated costs to be incurred in 1993 will be known with greater certainty when Southern California Edison Company ("Edison") files its 1993 Attrition Year advice letter. Consequently, the Settling Parties agree that the level of electric production expense adopted in the final revenue requirement decision in this proceeding should reflect the number of SONGS refuelings in Edison's 1993 Attrition Year advice letter. SDG&E's cost per refueling is $ 4.922 million (1993$) per unit.

The Settling Parties also agree that SDG&E's 1995 Attrition Year O&M expense adjustment should reflect SDG&E's share of the SONGS related O&M expense authorized in the Commission's decision on Edison's 1995 Test Year GRC application.

The Settlement Agreement revenues include recovery of $ 2.2 million of Nuclear Regulatory Commission fees related to SDG&E's share [*313] of SONGS ownership. The Settling Parties agree that any change in such fees which becomes law prior to the final revenue requirement decision setting January 1, 1993 revenue levels should be reflected in that decision.

6. California Utility Exchange ("CUE"). The Settling Parties agree that SDG&E should continue to participate in CUE, providing that it is generally cost effective.

7. Postage. The Settling Parties agree that SDG&E may increase the agreed upon O&M expense level set forth in subparagraph III.A.1., above, by the amount of increased postage expense SDG&E will incur in Test Year 1993 if the U.S. postage rate is raised prior to the final revenue requirement decision setting January 1, 1993 revenue levels. Appendix C shows the manner in which this adjustment shall be made.

8. Energy Services. The Settling Parties agree that beginning with Test Year 1993, SDG&E will no longer charge to Account 912 energy services expenses which are not related to demand-side management. Instead, these expenses will be charged to Account 903.

9. Officers' and Directors' Compensation. For purposes of setting the authorized revenues in this Settlement Agreement, the Settling [*314] Parties have specifically excluded the dollars requested by SDG&E related to bonuses payable to SDG&E's officers pursuant to the Long-Term Incentive Plan and the Short-Term Incentive Plan. In addition, the Settling Parties have specifically excluded the dollars requested by SDG&E related to the costs of directors' pensions.

10. Demand-side Management. This Settlement Agreement does not resolve potential issues between the Settling Parties regarding the appropriate level of demand-side management expense for the 1993 Test Year. This expense item will be the subject of a further agreement or litigation. The demand-side management expenses identified on the Summary of Earnings tables (Appendix A) are DRA's proposed level of expenses and are presented in those tables for illustrative purposes only.

These expenses do not include the $ 6.831 (1993 $) associated with SDG&E's proposed residential appliance efficiency incentives program. By ALJ Ruling dated April 2, 1992, consideration of this program and its funding requirements (including measurement and evaluation activities) have been transferred to R.91-08-003, I.91-08-002.

The Settlement Agreement revenues do not include [*315] SDG&E's requested demand-side management incentive rewards. SDG&E's entitlement to the requested rewards will be addressed later in this proceeding.

11. Post-Retirement Benefits Other Than Pensions ("PBOPs"). SDG&E's Application includes the request for $ 2.6 million (1993$) (plus the associated tax effects) to permit accrual of the costs associated with PBOPs for SDG&E's active and retired employees. The revenues set forth in the Summary of Earnings tables (Appendix A) do not reflect such costs. SDG&E's request rests upon Financial Accounting Standard ("FAS") 106 which requires the accrual of such costs for financial reporting purposes. The Commission is currently investigating in I. 90-07-037 whether or not FAS 106 should be followed for ratemaking purposes. Until the Commission resolves this issue, DRA believes that rate recovery beyond pay-as-you-go costs should not be authorized. The Settlement Agreement revenues do not include SDG&E's requested funding levels reflecting full PBOPs accrual costs.

It is anticipated that a decision in I.90-07-037 will be issued well before year end 1992. Accordingly, the Settling Parties agree that the level of PBOPs expense in 1993 [*316] Test Year rates should be governed by the Commission's decision in I.90-07-037. The Settling Parties further agree that if the Commission's I.90-07-037 decision authorizes accrual accounting of PBOPs costs for ratemaking purposes, any additional O&M expense (including tax effects) should be authorized in the final revenue requirements decision setting January 1, 1993 revenue levels, consistent with the decision in I.90-07-037. In the event a decision in I.90-07-037 is not issued before the final revenue requirements decision, but is subsequently issued approving accrual accounting for ratemaking purposes, SDG&E should be authorized to adjust its gas and electric margins consistent with that decision. These margin adjustments should be reflected in SDG&E's next rate proceedings where such margins are addressed.

12. Total Compensation Study. The Settling Parties acknowledge that conducting a total compensation study may not be practicable. Accordingly, they recommend that the Commission convene generic workshops to determine the feasibility and value of requiring such studies by the major California energy utilities and, if appropriate, the methodologies to be employed.

13. [*317] Low Income Rate Assistance ("LIRA") Administrative Costs. The Settlement Agreement O&M expense does not include any 1993 Test Year administrative costs for SDG&E's LIRA program. The Settling Parties agree that these costs should continue to be recorded in the LIRA balancing account and recovered through SDG&E's ECAC and BCAP proceedings.

14. Intervenor Fees. The Settling Parties agree that intervenor compensation awards should be recovered by SDG&E through its fuel clause proceedings by crediting the appropriate balancing account when the award payment is made. The revenues proposed in this Settlement Agreement do not include recovery of any such awards.

15. Emerging Business Enterprise ("EBE") Program Expenses. The Settling Parties agree that the total proposed 1993 Test Year revenues for SDG&E do not include any funding for Emerging Business Enterprise (Women/Minority Business Enterprise) expenses. The Commission has yet to open an investigation to review SDG&E's (and other utilities') EBE 1993 projected costs. The Settling Parties agree that it is uncertain whether or not the Commission will initiate and complete such an investigation in sufficient time to [*318] include the 1993 EBE projected expense in SDG&E's authorized 1993 rates. Accordingly, SDG&E has distributed testimony in this proceeding describing its 1993 programs and budget, SDG&E's "Report on Emerging Business Enterprises" (SDG&E-17). The Settling Parties agree that this report, together with those of DRA and other interested parties, should be examined in this proceeding. The Settling Parties further agree that, in the event funding for SDG&E's 1993 EBE expenses is not otherwise authorized prior to the final revenue requirement decision setting January 1, 1993 revenue levels, this decision should include the additional funding demonstrated to be reasonable through the evidence presented in the GRC hearings.

B. AMORTIZATION EXPENSE.

1. Abandoned Projects. The Settling Parties agree that no costs for gas-related abandoned or canceled projects included in SDG&E's application should be recovered through this GRC proceeding. The Settling Parties also agree that SDG&E should recover through amortization the costs of abandoned or canceled electric projects at the rate of $ 1.505 million per year for six years.

2. Software. The capitalization of software costs implicit [*319] in the agreed upon amortization expense level is governed by the following SDG&E policy: System software, purchased in conjunction with hardware, will be charged to the appropriate hardware plant account regardless of the level of cost. Software application

systems, whether developed internally or externally, will be capitalized in Account 303.1, if estimated costs exceed $ 100,000. Such costs may include evaluation, programming, and installation. SDG&E will continue to flow through the associated tax benefits.

C. AD VALOREM TAXES.

1. Order Instituting Investigation No. 92-03-052. The possibility exists that a settlement of litigation and potential litigation will be executed between the State Board of Equalization and various California counties and utilities, including SDG&E. Such a settlement may alter the method of property evaluation for ad valorem tax computation purposes. The Commission has issued I. 92-03-052 to assure the flow through to customers of any resulting reduction in property taxes achieved through the settlement. The ad valorem tax expense agreed upon in this Settlement Agreement is subject to change pending the outcome of I. 92-03-052.

D. PAYROLL [*320] TAXES.

1. FICA Limit. The payroll tax expense agreed upon by the Settling Parties assumes a FICA limit of $ 60,300 (1993 $). The Settling Parties agree that the adopted payroll tax expense ultimately reflected in SDG&E's 1993 Test Year revenue requirement should be the actual statutory limit for FICA withholding applicable to the 1993 calendar year. Accordingly, any change in the limit enacted prior to the final revenue requirement decision setting January 1, 1993 revenue levels should be applied in that decision.

E. RATE BASE.

1. Total Test Year Rate Base. The Settling Parties agree that the total rate base which the Commission should adopt for SDG&E's 1993 Test Year is $ 2,760.2 million. However, this amount is subject to adjustment for 1993 plant additions authorized in the Commission's low emission vehicle ("LEV") investigation as further described in subparagraph G.2., below.

2. Plant Held for Future Use ("PHFU"). SDG&E's proposed $ 255,000 in ratebase for PHFU has been excluded from the calculation of weighted average rate base for Test Year 1993. SDG&E agrees to the PHFU guidelines set forth in Appendix B to Southern California Edison's 1988 GRC decision [*321] (D.87-12-066), provided that: 1) the period for General Plant shall be five years instead of three years; and 2) paragraph 2b of Appendix B is revised to read as follows: "The need for each new item in PHFU must be justified in the next general rate proceeding." These modifica-

tions are consistent with the guidelines adopted for SDG&E's 1989-1991 rate case cycle in Decision No. 88-09-063.

F. SALES AND CUSTOMER LEVELS.

The parties agree that the Commission should adopt the forecasts of electric, gas, and steam sales and customer levels set forth in Appendix D. The electric forecast was determined in Decision No. 92-04-061, SDG&E's most recent ECAC. The gas forecast is DRA's recommended forecast which utilized more current historical data. The steam forecast reflects SDG&E's proposed estimate.

G. MISCELLANEOUS.

1. Research, Development and Demonstration ("RD&D"). The Settling Parties agree to continue the level of RD&D expenses agreed upon in SDG&E's Modified Attrition (A.91-03-001) Settlement Agreement. This treatment results in SDG&E recovering $ 6.0 million annually for funding of RD&D programs during this rate case cycle, exclusive of franchise fees and uncollectible [*322] expenses. The Settling Parties acknowledge that these funds are subject to one way balancing account treatment adopted in Decision No. 88-09-063. If at the end of 1993 or 1994 SDG&E has spent less than the total authorized annual funding, the Settling Parties agree that SDG&E should be allowed to carry forward the underexpenditure to the next year and add it to the authorized level of spending for that year. Over-expenditures in any year will be borne by shareholders and may not be carried forward. If, at the end of this rate case cycle (1993-1995) SDG&E has spent less than the total authorized funding, SDG&E will file an advice letter by March 30, 1996 to reduce rates by the unspent amount.

2. Low Emission Vehicle Program ("LEV"). SDG&E's application includes a request to recover O&M expenses and capital costs it desires to expend to continue its natural gas vehicle ("NGV") Marketing program, following the expiration of the existing funding authorized in Decision No. 91-07-017. SDG&E is also seeking $ 217,000 in this application for the purpose of funding an electric vehicle ("EV") Marketing program. This EV Marketing program is not included in SDG&E's RD&D program (discussed [*323] at Section III. G.1., above), but is separate and apart from the RD&D budget. The Settling Parties agree that the Clean Air Vehicles portion of the RD&D budget (including Hybrid Vehicle Development, Original Equipment Manufacturer Development, Emission Test Center and EV Battery Development) is appropriately addressed in this proceeding; however, both the NGV and EV Marketing program costs should be deferred to the LEV OII, I.91-10-029. Therefore, the to-

tal 1993 Test Year revenues agreed upon by the Settling Parties do not include recovery of any of these NGV and EV Marketing expenditures.

The Settling Parties agree that the authorization of additional NGV and EV Marketing program funding should be determined in the Commission's LEV investigation, I.91-10-029. However, the Settling Parties acknowledge that I.91-10-029 may not resolve the pending issues regarding the continuation of SDG&E's NGV program prior to the June 30, 1993 expiration of current program funding. SDG&E reserves the right to seek additional interim funding through I.91-10-029 or a separate application.

3. Miscellaneous Revenues. The Settling Parties agree that miscellaneous revenues are projected to be [*324] $ 17.861 million for the 1993 Test Year. The allocation of this amount among services is $ 15.057 million for electric, $ 2.804 million for gas.

4. Uncertain Future Environmental Expenditures. The Settling Parties recognize that various environmental-related expenditures SDG&E may make during the 1993 - 1995 rate case cycle are too uncertain to be estimated accurately at this time. The Settling Parties also recognize the need to establish a mechanism by which SDG&E may recover all such reasonably incurred costs. Accordingly, the Settling Parties propose that SDG&E be authorized to use the memorandum account procedures described below to recover all reasonably incurred costs, subject to subsequent reasonableness review.

a. Expenditures subject to memorandum account treatment. The two categories of expenditures to which the memorandum account procedures should apply are as follows:

* Remedial Activities Related to Hazardous Waste Sites. This category should include costs incurred in connection with former manufactured gas plant sites, as well as other types of sites. This category should also include all hazardous waste clean-up costs pertaining to the ESCO substation [*325] construction site incurred after the date of execution of this Settlement Agreement. Recoverable expenses should include investigation expenses related to the remediation at the site, as well as all expenditures associated with actual clean-up activity.

Recoverable expenses should not include the costs of preliminary investigations which are conducted to provide an initial assessment of the contamination at a site and the associated health risks. Revenues for preliminary investigations are included in the Settlement Agreement revenue requirement.

* Environmental Compliance Activities Not Funded Through the Settlement Agreement Revenues. The costs of compliance activities recoverable through the

memorandum account process described herein include the costs of such activities which the Settling Parties agree are not recovered in the Settlement Agreement revenues, including:

i. SDG&E Project No. 91078: Encina and South Bay Secondary Containment Waste Water Treatment Facilities,

ii. SDG&E Project No. 91079: Senate Bill 14-Hazardous Waste Source Reduction,

iii. SDG&E Project No. 91081: Bay and Estuary Plan -- mitigation measures required in connection with NPDES permits, [*326]

iv. SDG&E Project No. 91080: Plant modifications necessary to comply with proposed APCD Rule 69, and

v. Compliance activities in response to other subsequently adopted environmental regulations.

b. Description of memorandum account procedures. SDG&E will pursue recovery of the environmental expenditures subject to memorandum account treatment through the following procedures:

* Hazardous Waste Management Projects - For each hazardous waste management project site, SDG&E shall file an advice letter which complies with the informational requirements previously specified for such advice letters in Decision No. 88-09-020. Following Commission approval of the advice letter request, expenditures incurred on such projects shall be recorded in SDG&E's hazardous waste management memorandum account authorized by Resolution No. 2987 (March 31, 1992). Costs recorded in this account shall be recoverable in rates to the extent the Commission subsequently determines them to have been reasonably incurred.

* Environmental Compliance Activities (except Rule 69-related NOx modifications at SDG&E power plants) - In Decision No. 91-10-046, the Commission authorized SDG&E to establish [*327] an environmental compliance memorandum account and to record therein certain environmental compliance expenditures incurred in 1992, following the filing and approval of an advice letter. The Settling Parties agree that the previously-ordered advice letter process should be retained through the 1993-1995 rate case cycle and expanded to include all applicable environmental compliance expenditures incurred during that cycle, except Rule 69-related NOx modifications at SDG&E power plants. Expenses recorded in the environmental compliance memorandum account should be reviewed for reasonableness in a future SDG&E ECAC, or such other proceeding as the Commission shall designate. Expenses found to be reasonable will be included in SDG&E's rates.

* Rule 69-related NOx modifications at SDG&E power plants - The Settling Parties concur that the magnitude and significance of certain Rule 69-related NOx modifications at SDG&E power plants may require more extensive review prior to SDG&E's receipt of authority to record the costs of these compliance activities in a memorandum account. Accordingly, for Rule 69-related NOx modifications at SDG&E power plants the Settling Parties have agreed [*328] that, following the adoption of the final Rule 69 by the San Diego Air Pollution Control District ("APCD"), SDG&E may request permission to open a memorandum account via an advice letter filing for each generating unit that may require retrofit. In its advice letter filing, SDG&E will provide:

i. The Rule 69 compliance schedule and a forecast of compliance costs, including operation and maintenance costs, and refurbishment costs.

ii. An analysis of the long-term plan for each plant for which SDG&E seeks permission to obtain a memorandum account.

iii. A comparative assessment of the long-term costs of retrofitting and operating the plant to various alternatives to retrofits. The alternative analysis will consider retrofits, plant retirements, repowering, and emission credits, if any, as applied under Rule 69 to the SDG&E system.

Recognizing that the APCD compliance schedule may require immediate action by SDG&E, DRA will review the Rule 69 advice letter and offer a recommendation to the Commission within 60 days of the Advice Letter filing. Upon issuance of a Commission resolution, SDG&E will be authorized to record its Rule 69-related NOx modification expenses in a memorandum [*329] account. A separate authorization and account will be used for each generating unit. The recorded memorandum account expenses will be reviewede for reasonableness in a separate SDG&E application or a future GRC. Expenses found to be reasonable will be included in SDG&E rates. SDG&E will include the cost of complying with Rule 69 in future BRPU filings.

5. Photovoltaic Systems. The Settling Parties agree that SDG&E will inform customers who apply for uneconomic line extensions of alternate energy sources including, but not limited to, photovoltaic systems. The information provided will include general ranges of costs for the various alternatives and will encourage customers to conduct their own specific inquiries on alternatives to uneconomic line extensions. The information SDG&E provides also will include an appropriate disclaimer eliminating any implied warranty of the quality or cost of the energy sources identified. SDG&E will consult with its DSM Advisory Committee concerning the content of the information provided.

6. Attrition. SDG&E's Application requested higher than normal attrition allowances in 1994 and 1995, based on its forecast of capital additions. [*330] DRA proposed lower than normal attrition allowances for SDG&E based on imputing additional productivity increases in 1994 and 1995.

The Settling Parties agree that these proposals shall not be adopted in this settlement, nor shall the Settling Parties pursue these proposals in SDG&E's 1994 or 1995 attrition proceedings.

IV.

ADDITIONAL TERMS AND CONDITIONS

A. PERFORMANCE.

The Settling Parties agree to perform diligently, and in good faith, all actions required or implied hereunder, including, but not necessarily limited to, the execution of any other documents required to effectuate the terms of this Settlement Agreement, and the preparation of exhibits for, and presentation of witnesses at, any required hearings to obtain the approval and adoption of this Settlement Agreement by the Commission. No Settling Party will contest in this proceeding, or in any other forum, or in any manner before this Commission, the recommendations contained in this Settlement Agreement. It is understood by the Settling Parties that time is of the essence in obtaining the Commission's approval of this Settlement Agreement and that all will extend their best efforts to ensure its adoption.

B. [*331] CONTRIBUTION OF UCAN.

For purposes of determining intervenor compensation, the undersigned parties acknowledge the contribution of UCAN during the discovery phase and settlement negotiation process. During the discovery phase, UCAN was the most active party, aside from DRA. Because the Settlement Agreement was reached prior to the date for filing intervenor testimony, UCAN did not file formal testimony. However, it presented expert substantiation of its positions during the settlement phase of the case and participated in an informed, expert manner.

C. THE PUBLIC INTEREST.

The Settling Parties agree jointly by executing and submitting this Settlement Agreement that the relief requested herein is just, fair and reasonable, and in the public interest.

The Settling Parties acknowledge the value of including all active participants in this case in the settlement process. Accordingly, the Settling Parties agree that in any future SDG&E rate proceedings, reasonable efforts shall be made to include all active parties at the commencement of settlement negotiations.

D. NON-PRECEDENTIAL EFFECT.

This Settlement Agreement is not intended by the Settling Parties to be binding precedent [*332] for any future proceeding. The Settling Parties have assented to the terms of this Settlement Agreement only for the purpose of arriving at the settlement embodied in this Settlement Agreement. Each Settling Party expressly reserves its right to advocate, in current and future proceedings, positions, principles, assumptions, arguments and methodologies which may be different than those underlying this Settlement Agreement, and the Settling Parties expressly declare that, as provided in Rule 51.8 of the Commission's Rules of Practice and Procedure, this Settlement Agreement should not be considered as a precedent for or against them.

E. INDIVISIBILITY.

This Settlement Agreement embodies compromises of the Settling Parties' positions. No individual term of this Settlement Agreement is assented to by any Settling Party except in consideration of the other Settling Parties' assents to all other terms. Thus, the Settlement Agreement is indivisible and each part is interdependent on each and all other parts. Any party may withdraw from this Settlement Agreement if the Commission modifies, deletes from, or adds to the disposition of the matters stipulated herein. The Settling Parties [*333] agree, however, to negotiate in good faith with regard to any Commission-ordered changes in order to restore the balance of benefits and burdens, and to exercise the right to withdraw only if such negotiations are unsuccessful.

The Settling Parties acknowledge that the positions expressed in the Settlement Agreement were reached after consideration of all positions advanced in the prepared testimony of SDG&E and DRA, as well as numerous proposals offered by UCAN and the City of San Diego during the settlement negotiations. This document sets forth the entire agreement of Settling Parties on all of those issues, except as specifically described within the Settlement Agreement. The terms and conditions of this Settlement Agreement may only be modified in writing subscribed by all Settling Parties.

F. APPENDICES.

APPENDICES A through D to this Settlement Agreement are part of the agreement of the Settling Parties and are incorporated by reference.

Dated this 8th day of May, 1992 in San Diego, California.

By: JOHN A. YAGER
Program Manager
DIVISION OF RATEPAYER
ADVOCATES of the California
Public Utilities Commission

By: STEVEN L. BAUM
Senior Vice President Law
and Corporate [*334] Affairs and
General Counsel
SAN DIEGO GAS & ELECTRIC
COMPANY

By: MICHAEL SHAMES
Executive Director
UTILITY CONSUMERS' ACTION
NETWORK

By: PETER V. ALLEN
Deputy City Attorney
CITY OF SAN DIEGO

APPENDIX A

SUMMARY OF EARNINGS

Combined Departments

(000's)

	DRA 1993 Report	SDG&E Request	Settlement
REVENUES	$ 1,132,287	$ 1,227,736	$ 1,161,466
O & M EXPENSE			
Supply	$ 333	$ 243	$ 321
Storage	$ 179	$ 280	$ 230
Production	$ 102,796	$ 115,730	$ 104,684
Transmission	$ 13,996	$ 14,738	$ 14,142
Distribution	$ 49,993	$ 55,013	$ 52,283
Customer Accounting	$ 35,248	$ 38,477	$ 36,749
Uncollectibles	$ 3,017	$ 3,435	$ 3,092
Administrative & General	$ 93,088	$ 103,392	$ 100,281
Franchise Fees	$ 21,687	$ 23,579	$ 22,231
Demand-side Management	$ 51,209	$ 53,368	* $ 45,892
Energy Services	$ 0	$ 3,076	$ 2,000
Adjustments	($ 5,735)	$ 0	($ 1,793)
Subtotal ($ 1988)	$ 365,811	$ 411,331	$ 380,112
Labor Escalation	$ 28,113	$ 34,566	$ 30,177
Non-Labor Escalation	$ 30,014	$ 41,980	$ 29,947
TOTAL O & M EXPENSE ($ 1993)	$ 423,938	$ 487,877	$ 440,236
Depreciation/Amortization	$ 219,548	$ 228,677	$ 222,859
Ad Valorem Taxes	$ 42,911	$ 43,823	$ 43,276
Payroll & Misc. Taxes	$ 6,092	$ 7,437	$ 7,437
Income Taxes	$ 147,954	$ 154,762	$ 150,935
TOTAL OPERATING EXPENSE	$ 840,443	$ 922,576	$ 864,743
Net Operating Income	$ 291,844	$ 305,160	$ 296,723
Rate Base	$ 2,714,824	$ 2,838,694	$ 2,760,210
Rate of Return	10.75%	10.75%	10.75%

[*335]

* DRA's DSM number adjusted for the Pilot Bidding Program deferral to the DSM OII/OIR.

SUMMARY OF EARNINGS

Electric Department

(000's)

	DRA 1993 Report	SDG&E Request	Settlement
REVENUES	$ 955,762	$ 1,037,645	$ 978,684
O & M EXPENSE			
Production	$ 102,244	$ 115,124	$ 104,089
Transmission	$ 9,017	$ 9,554	$ 9,098
Distribution	$ 32,519	$ 37,229	$ 34,733
Customer Accounting	$ 22,816	$ 24,906	$ 23,787
Uncollectibles	$ 2,578	$ 2,932	$ 2,636
Administrative & General	$ 69,687	$ 77,702	$ 75,017
Franchise Fees	$ 18,160	$ 19,720	$ 18,568
Demand-side Management	$ 42,666	$ 44,825	* $ 37,649
Energy Services	$ 0	$ 2,018	$ 1,620
Adjustment	($ 4,145)	$ 0	($ 1,294)
Subtotal ($ 1988)	$ 295,542	$ 334,010	$ 305,903
Labor Escalation	$ 21,512	$ 26,965	$ 23,069
Non-Labor Escalation	$ 24,812	$ 34,534	$ 24,694
TOTAL O & M EXPENSE ($ 1993)	$ 341,866	$ 395,509	$ 353,666
Depreciation/Amortization	$ 190,584	$ 198,615	$ 193,469
Ad Valorem Taxes	$ 37,353	$ 38,171	$ 37,647
Payroll & Misc. Taxes	$ 4,567	$ 5,569	$ 5,569
Income Taxes	$ 128,308	$ 134,603	$ 130,980
TOTAL OPERATING EXPENSE	$ 702,678	$ 772,467	$ 721,331
Net Operating Income	$ 253,084	$ 265,178	$ 257,353
Rate Base	$ 2,354,270	$ 2,466,775	$ 2,393,984
Rate of Return	10.75%	10.75%	10.75%

[*336]

* DRA's DSM number adjusted for the Pilot Bidding Program deferral to the DSM OII/OIR.

SUMMARY OF EARNINGS

Gas Department

(000's)

	DRA 1993 Report ($ 93)	SDG&E Request ($ 93)	Tentative Settlement ($ 93)
REVENUES	$ 174,932	$ 188,220	$ 181,142

	DRA 1993 Report ($ 93)	SDG&E Request ($ 93)	Tentative Settlement ($ 93)
O & M EXPENSE			
Supply	$ 619	$ 578	$ 578
Storage	$ 218	$ 344	$ 281
Transmission	$ 5,862	$ 6,020	$ 5,941
Distribution	$ 21,217	$ 21,548	$ 21,288
Customer Accounting	$ 14,681	$ 16,445	$ 15,316
Uncollectibles	$ 439	$ 503	$ 456
Administrative & General	$ 25,804	$ 30,011	$ 28,000
Franchise Fees	$ 3,497	$ 3,820	$ 3,628
Demand-side Management	$ 10,492	$ 10,399	* $ 10,035
Energy Services	$ 0	$ 1,293	$ 463
Adjustment	($ 1,895)	$ 0	($ 594)
TOTAL O & M EXPENSE	$ 80,934	$ 90,961	$ 85,392
Depreciation/Amortization	$ 28,712	$ 29,811	$ 29,139
Ad Valorem Taxes	$ 5,541	$ 5,635	$ 5,612
Payroll & Misc. Taxes	$ 1,494	$ 1,830	$ 1,830
Income Taxes	$ 19,558	$ 20,071	$ 19,867
TOTAL OPERATING EXPENSE	$ 136,239	$ 148,308	$ 141,840
Net Operating Income	$ 38,693	$ 39,912	$ 39,302
Rate Base	$ 359,933	$ 371,270	$ 365,601
Rate of Return	10.75%	10.75%	10.75%

[*337]

* DRA's DSM number adjusted for the Pilot Bidding Program being deferred to the DSM OII/OIR.

SUMMARY OF EARNINGS

Steam Department

(000's)

	DRA 1993 Report	SDG&E Request	Settlement
REVENUES	$ 1,508	$ 1,871	$ 1,623
O & M EXPENSE			
Production	$ 552	$ 606	$ 595
Distribution	$ 62	$ 66	$ 63
Customer Accounting	$ 4	$ 4	$ 4
Uncollectibles	$ 0	$ 0	$ 0
Administrative & General	$ 286	$ 452	$ 305

	DRA 1993 Report	SDG&E Request	Settlement
Franchise Fees	$ 32	$ 39	$ 35
Adjustment	($ 36)	$ 0	($ 11)
Subtotal ($ 1988)	$ 900	$ 1,167	$ 991
Labor Escalation	$ 82	$ 104	$ 95
Non-Labor Escalation	$ 71	$ 136	$ 76
TOTAL O & M EXPENSE ($ 1993)	$ 1,053	$ 1,407	$ 1,162
Depreciation/Amortization	$ 252	$ 251	$ 251
Ad Valorem Taxes	$ 17	$ 17	$ 17
Payroll & Misc. Taxes	$ 31	$ 38	$ 38
Income Taxes	$ 88	$ 88	$ 88
TOTAL OPERATING EXPENSE	$ 1,441	$ 1,801	$ 1,556
Net Operating Income	$ 67	$ 70	$ 67
Rate Base	$ 621	$ 649	$ 625
Rate of Return	10.75%	10.75%	10.75%

APPENDIX B

SAN DIEGO GAS & ELECTRIC COMPANY

1993 GENERAL RATE CASE

A. 91-11-024

LABOR, NON-LABOR AND OTHER

OPERATING & MAINTENANCE EXPENSE [*338] ALLOCATION *

* Note: Excludes Franchise Fees & Uncollectibles

(000 $)

ELECTRIC DEPARTMENT (1988 $)

LABOR	$ 115,915
NON-LABOR	$ 119,540
OTHER	$ 49,245
TOTAL	$ 284,699

GAS DEPARTMENT (1988 $)

LABOR	$ 32,183
NON-LABOR	$ 23,736
OTHER	$ 13,214
TOTAL	$ 69,133

STEAM DEPARTMENT (1988 $)

LABOR	$ 435
NON-LABOR	$ 342
OTHER	$ 179
TOTAL	$ 956

ELECTRIC DEPARTMENT (1988 $)

	LABOR			NON-LABOR		
	SDG&E	DRA	SETTLE-MENT	SDG&E	DRA	SETTLE-MENT
PRODUCTION *	$ 55,222	$ 51,114	$ 51,998	$ 46,726	$ 38,891	$ 39,852
TRANSMISSION	$ 5,658	$ 5,727	$ 5,727	$ 3,670	$ 3,290	$ 3,371
DISTRIBUTION	$ 21,756	$ 19,999	$ 20,825	$ 15,473	$ 12,520	$ 13,908
CUSTOMER ACCTG	$ 14,283	$ 13,002	$ 13,562	$ 8,397	$ 7,456	$ 7,867
A&G	$ 21,394	$ 19,478	$ 19,775	$ 35,441	$ 19,633	$ 20,594
DEM.-SIDE MGMT **	$ 4,623	$ 4,364	$ 4,036	$ 40,202	$ 38,302	$ 33,613
ENERGY SERVICES	$ 1,386	$ 0	$ 1,285	$ 632	$ 0	$ 335
ADJUSTMENT	$ 0	($ 4,145)	($ 1,294)	$ 0	$ 0	$ 0

	LABOR			NON-LABOR		
	SDG&E	DRA	SETTLE-MENT	SDG&E	DRA	SETTLE-MENT
TOTAL	$ 124,322	$ 109,539	$ 115,915	$ 150,541	$ 120,092	$ 119,540

* Note: SDG&E's share of SONGS O&M is $ 38,523 (labor) and $ 20,964 (non-labor) in 1988$

** Note: Used DRA's DSM Report number for Settlement scenario adjusted to defer Pilot Bidding Program cost

[*339]

ELECTRIC DEPARTMENT (1988 $)

	OTHER			TOTAL		
	SDG&E	DRA	SETTLE-MENT	SDG&E	DRA	SETTLEMENT
PRODUCTION	$ 13,176	$ 12,239	$ 12,239	$ 115,124	$ 102,244	$ 104,089
TRANSMISSION	$ 0	$ 0	$ 0	$ 9,328	$ 9,017	$ 9,098
DISTRIBUTION	$ 0	$ 0	$ 0	$ 37,229	$ 32,519	$ 34,733
CUSTOMER ACCTG	$ 2,225	$ 2,358	$ 2,358	$ 24,906	$ 22,816	$ 23,787
A&G	$ 20,867	$ 30,576	$ 34,648	$ 77,702	$ 69,687	$ 75,017
DEM.-SIDE MGMT *	$ 0	$ 0	$ 0	$ 44,825	$ 42,666	$ 37,649
ENERGY SERVICES	$ 0	$ 0	$ 0	$ 2,018	$ 0	$ 1,620
ADJUSTMENT	$ 0	$ 0	$ 0	$ 0	($ 4,145)	($ 1,294)
TOTAL	$ 36,268	$ 45,173	$ 49,245	$ 311,132	$ 274,804	$ 284,699

GAS DEPARTMENT (1988 $)

	LABOR			NON-LABOR		
	SDG&E	DRA	SETTLEMENT	SDG&E	DRA	SETTLEMENT
SUPPLY	$ 1,029	$ 1,011	$ 1,029	$ 272	$ 301	$ 272
STORAGE	$ 76	$ 77	$ 77	$ 204	$ 102	$ 153
TRANSMISSION	$ 2,676	$ 2,495	$ 2,586	$ 1,499	$ 1,549	$ 1,524
DISTRIBUTION	$ 13,882	$ 13,269	$ 13,517	$ 3,836	$ 4,143	$ 3,970
CUSTOMER ACCTG	$ 7,781	$ 7,083	$ 7,388	$ 4,574	$ 4,061	$ 4,285
A&G	$ 7,305	$ 6,656	$ 6,756	$ 11,958	$ 5,902	$ 6,227
DEM.-SIDE MGMT *	$ 1,071	$ 1,083	$ 1,017	$ 7,472	$ 7,534	$ 7,226
ENERGY SERVICES	$ 558	$ 0	$ 301	$ 500	$ 0	$ 79
ADJUSTMENT	$ 0	($ 1,554)	($ 488)	$ 0	$ 0	$ 0
TOTAL	$ 34,378	$ 30,120	$ 32,183	$ 30,315	$ 23,592	$ 23,736

[*340]

* Note: Used DRA's DSM Report number for Settlement scenario adjusted to defer Pilot Bidding Program cost

GAS DEPARTMENT (1988 $)

	OTHER			TOTAL		
	SDG&E	DRA	SETTLEMENT	SDG&E	DRA	SETTLEMENT
SUPPLY	($ 980)	($ 980)	($ 980)	$ 321	$ 332	$ 321
STORAGE	$ 0	$ 0	$ 0	$ 280	$ 179	$ 230
TRANSMISSION	$ 934	$ 934	$ 934	$ 5,109	$ 4,978	$ 5,044
DISTRIBUTION	$ 0	$ 0	$ 0	$ 17,718	$ 17,412	$ 17,487
CUSTOMER ACCTG	$ 1,212	$ 1,285	$ 1,285	$ 13,567	$ 12,429	$ 12,958
A&G	$ 5,974	$ 10,557	$ 11,976	$ 25,237	$ 23,115	$ 24,959
DEM.-SIDE MGMT *	$ 0	$ 0	$ 0	$ 8,543	$ 8,617	$ 8,243
ENERGY SERVICES	$ 0	$ 0	$ 0	$ 1,058	$ 0	$ 380
ADJUSTMENT	$ 0	$ 0	$ 0	$ 0	($ 1,554)	($ 488)
TOTAL	$ 7,140	$ 11,796	$ 13,214	$ 71,833	$ 65,508	$ 69,133

STEAM DEPARTMENT (1988 $)

	LABOR			NON-LABOR		
	SDG&E	DRA	SETTLEMENT	SDG&E	DRA	SETTLEMENT
PRODUCTION	$ 348	$ 301	$ 328	$ 258	$ 251	$ 267
DISTRIBUTION	$ 50	$ 47	$ 47	$ 17	$ 16	$ 16
CUSTOMER ACCTG	$ 2	$ 2	$ 2	$ 1	$ 1	$ 1
A&G	$ 73	$ 67	$ 69	$ 224	$ 54	$ 58
ADJUSTMENT	$ 0	($ 36)	($ 11)	$ 0	$ 0	$ 0
TOTAL	$ 473	$ 381	$ 435	$ 500	$ 322	$ 342

[*341]

STEAM DEPARTMENT (1988 $)

	OTHER			TOTAL		
	SDG&E	DRA	SETTLEMENT	SDG&E	DRA	SETTLEMENT
PRODUCTION	$ 0	$ 0	$ 0	$ 606	$ 552	$ 595
DISTRIBUTION	$ 0	$ 0	$ 0	$ 67	$ 63	$ 63
CUSTOMER ACCTG	$ 0	$ 0	$ 0	$ 4	$ 4	$ 4
A&G	$ 155	$ 166	$ 179	$ 452	$ 287	$ 305
ADJUSTMENT	$ 0	$ 0	$ 0	$ 0	($ 36)	($ 11)
TOTAL	$ 155	$ 166	$ 179	$ 1,129	$ 870	$ 956

APPENDIX C

POSTAGE CALCULATION

The Settling Parties agree the Commission should adopt the postage calculation and forecast as referenced in Paragraph III.A.5, and shown below.

A standard number of pieces of mail per customer is found by dividing the numbers of pieces of mail in the most recent year for which recorded data is available (1991) by the number of customers in the most recent year for which recorded data is available.

This the average number of pieces per customer is then multiplied by the number of customers estimated for the test year. That total is then multiplied by the current (nominal) postage rate(s).

The formula is applied to each postal class to develop the aggregate postage requirement.

	1991	1993
Customers	1,111,225	1,152,843
Pieces Per Customer	13.44	13.44

[*342]

	1992	PIECES		PIECES	POSTAGE
CLASS	RATE	(000)	(%)	(000)	EXPENSE
Carrier Route	0.230	11,059	74.1%	11,477	$ 2,639,727
Presort	0.248	764	5.1	793	196,645
Presort + Fee	0.258	1,641	11.0	1,703	439,244
5 Digit Bar	0.233	75	0.5	78	18,186
3 Digit Bar	0.239	25	0.2	26	6,244
Zip + 4	0.242	1,366	9.1	1,418	343,044
Total		14,930	100%	15,494	$ 3,643,044

Allocation of postage expense for the 1993 Test Year, by service department is as follows:

Electric	64.73%	$ 2,358,100
Gas	35.26%	1,284,500
Steam	.01%	400

APPENDIX D

AGREED SALES AND CUSTOMER LEVELS

1. Electric Sales and Customers The Settling Parties agree the Commission should adopt the following forecast of electric sales and customers in total and by class:

Class	Millions of Kwhrs	Year End Customers
Residential	5,572.3	1,029,984
Commercial	5,609.6	116,810
Industrial	3,193.9	547
Agricultural Power	236.1	3,961
Streetlighting	67.3	1,540
Resale	0.2	1
Total	14,679.4	1,152,843

2. Gas Sales and Customers The Settling Parties agree that the Commission should adopt the following forecast of gas sales and customers [*343] in total and by class:

Class	Thousands of Therms	Year End Customers
Residential	338.2	679,089
Non-Residential	352.8	28,029
Sub-total	691.0	707,118
Interdepartmental	384.1	
Total	1,075.1	

3. Steam Sales and Customers The Settling Parties agree that the Commission should adopt the following forecast of steam sales and customers:

	Thousands of Pounds	Year End Customers
Schedule 1	25,805	7
Schedule 2	0	0
Total	25,805	7

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