ALJ/jn/vdl

Decision 83 12 065 December 20, 1983

ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY for authority to increase its rates and charges for electric, gas and steam service.	Application 82-12-57 (Filed December 24, 1982)

(See Appendix A for appearances.)

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INTERIM OPINION

1. Proceeding Background

San Diego Gas & Electric Company (SDG&E) filed its notice of intention (NOI 79) on August 27, 1982 to file an application for a general rate increase for the rate year 1984 and an attrition year 1985. SDG&E amended its NOI on October 13, 1982 and it was subsequently accepted for filing by the Commission on October 25, 1982. The case was processed under the new revised Rate Case Plan authorized by the Commission in Resolution ALJ-149 dated October 20, 1982, and amended by Decision (D.) 82-11-072 dated December 15, 1982 and D.83-01-001 dated January 12, 1983. Under the Rate Case Plan SDG&E filed Application (A.) 82-12-57 on December 24, 1982. As proposed in that application, SDG&E requests increases totaling \$126.8 million per year to offset increased cost of doing business. The request includes an 8.27% increase or \$102.9 million for the electric department, a 3.83% or \$23.8 million increase for the gas department, and a 8.76% or \$.146 million for its steam operations. During the course of hearings on the matter, SDG&E effectively reduced its total request from the \$126.8 million to \$65.3 million.

A prehearing conference and 64 days of hearings were held from February 2 to July 22, 1983 all in San Diego before Administrative Law Judge (ALJ) Albert C. Porter. In accordance with the Rate Case Plan, an update hearing was held September 19, 1983 and oral argument was held before the Commission en banc on October 12, 1983. Concurrent briefs were filed by the parties on August 29, 1983. Briefs were received from those parties most active in the proceeding including, besides SDG&E and the Commission's staff (staff), the following:

California Association of Utility Shareholders	(CAUS, shareholders)
California Energy Commission	(CEC)
California-Nevada Community Action Association	(CAL-NEVA)
Federal Executive Agencies	(FEA)
Independent Energy Producers	(IEP)
Insulation Contractors Association	(ICA)
Edward J. Neuner, for himself	(Neuner)
City of San Diego	(San Diego)
San Diego Rock Producer's Association	(Rock Producers)
Schools Committee for Reducing Utility Bills	(SCRUB)
The Sierra Club	(Sierra Club)
Welfare Rights Organization	(WRO)
Western Mobilehome Association	(WMA)

2. Decision Summary

By this decision the Commission grants SDG&E permission to raise its rates by $14.315 million per year effective January 1. SDG&E had requested a $127 million increase when it filed its application on Christmas Eve in 1982. After the Commission held 65 days of hearings, all in San Diego, the company had pared its request to $65 million whereas the Commission's staff had recommended no increase at all.

The Commission held four sessions over two days last May to hear comments from the customers of SDG&E. These were far ranging. Persons on fixed incomes deplored the possibility of increased power bills; some customers thought SDG&E was mismanaged by overpaid managers; some people wanted more spent on conservation and some less; and almost everyone thought it was time for SDG&E to tighten its belt as everyone else has had to do.

In designing the new electric rates that will go into effect on January 1, the Commission orders SDG&E to move to a full marginal cost allocation of revenues to its various customers. The method attempts to put the incremental cost of providing energy on those customers most responsible for that cost. The method causes some interesting effects on the increases for the various classes of service. On the average, residential rates will go down 4.1%, commercial and industrial customers will pay an average of 2.4% more, and agricultural users will pay 3.7% less. Streetlighting rates will not be changed until SDG&E comes up with a satisfactory marginal cost study for that service, which the Commission orders the utility to complete and present in 1985.

One of the stickiest issues in the case was what to do with SDG&E's Blythe Site, a piece of property left over from the company's abandoned attempt to develop a nuclear generating facility near Blythe, California, which was known as the Sundesert project. Most participants in the proceedings urged the Commission to keep the site available for a future power plant, but, at the same time, urged that it be taken out of the company's rate base so customers would not have to support it. We are holding this issue open for further hearings in January 1984. Pending resolution of the question of the Blythe Site, we will maintain the status quo, i.e. $45 million in rate base earning a rate of return of 10.59%.

The Commission's decision cuts the return on equity capital of SDG&E's stockholders to 16% compared to the current 16.25%

authorized for 1982 and 1983. The overall rate of return granted the company is 12.82%.

The Commission orders SDG&E to cut back its conservation activities in 1984 to about the 1982 level. In particular, heavy cuts are made in requested 1984 funds for support programs for the commercial/industrial sector and residential audits; modest cuts are made to weatherization programs. It should be noted that SDG&E was in favor of even heavier cuts; its requested funds reflected what it believes would be necessary to continue its programs at a level equivalent to past years' levels and growth. The Commission adopts a conservation policy for SDG&E for the first time. The policy stresses supporting mandated programs, requiring new programs to be cost-effective, phasing out incentive-payment programs not shared by all ratepayers or which would be undertaken by customers without incentives, and continuing programs that are worthwhile from the standpoint of equity.

The Welfare Rights Organization convinced the Commission to adopt several new tariff provisions which enlarge the rights of SDG&E's customers concerning payment of bills and termination of service. SDG&E will now have to notify customers of the reason their service is being terminated, payment plans for overdue bills will be more flexible, informal litigation of bills by the Commission's staff will be easier to initiate, and customers will be better informed of options they have under SDG&E's tariffs.

The decision sets up a mechanism which will allow SDG&E to adjust its rates on January 1, 1985 for valid and specific increases in the cost of doing business. No further general rate increase will be considered by the Commission before January 1, 1986.

3. Statements of SDG&E Customers

During the hearings on this application, four sessions were held to receive comments and questions from SDG&E's customers. The sessions were held morning and evening on May 23, and afternoon and evening on May 25 before assigned Commissioner Priscilla C. Grew and the ALJ. About 50 persons addressed the Commission out of some 200 who attended. Their comments were far-ranging, all of which the Commission has considered in coming to its decision in this proceeding. In general, customers had the following concerns and comments:

The seemingly never-ending increases granted SDG&E by the Commission.

The special needs of residents in the eastern areas of SDG&E's service territory because of the warm weather.

The devastating effect of utility increases on persons with fixed income, particularly the elderly and retired.

The budget crunch faced by schools and other community services because of Proposition 13 cutbacks.

The lack of incentives to conserve by multi-unit complexes that are not individually metered.

Misalignment of lifeline allowances.

Mismanagement at SDG&E by overpaid managers.

Dividends for SDG&E stockholders. Some persons thought they were too high, some too low.

Not enough attention to or money spent on conservation.

Too much money spent on conservation, particularly rebates.

Ratepayer support of SDG&E's lobbying efforts.

Unnecessary funds spent on advertising.

Unwillingness of SDG&E to cut back on expenses as everyone else has had to do.

Inability of the Commission to protect consumers from gouging by the utilities.

Commission staff and utility agreements.

Lack of development of alternative energy sources.

SONGS and Sundesert are losers the ratepayers should not have to pay for.

SDG&E is not supportive of small, independent energy producers.

Discounts given to its employees by SDG&E.

Solar water heater installations do not pay off.

Meters should be read only once per year with average billings made for the other months.

SDG&E has been very supportive of conservation.

SDG&E's disconnect procedures are unfair.

Low-income weatherization programs are effective and should be continued.

4. Revenues

SDG&E and the staff reached accord on estimates for electric, gas, and steam sales for the test year. No other party presented evidence on sales and revenues under present rates. The stipulated sales estimates are contained in Exhibit 110. SDG&E and the staff also agreed that the electric revenue adjustment mechanism (ERAM) and the supply adjustment mechanism (SAM) should continue in effect through the test year. Therefore, they agreed on the calculation of electric and gas revenues at present rates[1] as shown on Table 1 following.

We note that neither SDG&E or the staff is comfortable with the other's method of forecasting sales and a good deal of hearing time was spent by the two parties contesting the econometric models used for forecasting. Because of ERAM and SAM, we will expect the parties in the future, if possible, to come to their stipulations early in the proceedings and thereby save costly hearing time.

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[1] Present rates are those authorized by D.83-06-079 dated June 29, 1983 in A.83-03-56.

SDG&E recommends that its ERAM be expanded to cover resale revenues which are not under the jurisdiction of this Commission. SDG&E claims they are as difficult to forecast as jurisdictional revenues and are estimated by SDG&E to be $3,153,000 for 1984. We will not adopt the recommendation because the revenues are not under our jurisdiction.

TABLE 1

REVENUES AT PRESENT RATES
TEST YEAR 1984
($1,000s)

Electric Department	
Residential	$199,897
Commercial & Industrial	307,549
Agricultural Power	8,882
Street Lighting	9,412
Resale	1,567
Total Base Rev. from Cust.	$527,307
Miscellaneous	6,929
Deferred Revenue	-5,819
Total Electric Department	$528,417
Gas Department	
Residential	$ 52,658
Nonresidential	38,344
Subtotal	$ 91,002
Interdepartmental	15,649
Miscellaneous	1,031
Subtotal	$ 16,680
Deferred Revenue	-4,254
Total Gas Department	$103,428
Total Steam Department	282
Total System	$632,127

5. Expenses - Common Issues

There are several issues common to the electric, gas, and Steam Department expense estimates of the parties. We will address these before discussing specific expense issues.

5.1 Escalation Factors

A large majority of the expense estimates presented by SDG&E and the staff involved application of escalation factors. Table 2 is a summary of the factors used by SDG&E and the staff for labor and nonlabor expense estimates.

5.1.1 Nonlabor Escalation Factors

SDG&E called witness Mariana McNeill, Vice-President and Director of Cost Forecasting Services for Data Resources Incorporated (DRI). McNeill presented updated DRI utility-specific forecasts as of March 1983 and explained the method employed by DRI to estimate specific nonlabor escalation factors for SDG&E. DRI's analysis for SDG&E compares escalation in SDG&E's operation and maintenance costs to national wage and price movements over selected intervals. DRI attempts to compare SDG&E's escalation experience to the national aggregate measures by creating material and services cost indexes for the various goods and services required to operate and maintain SDG&E'S facilities. The composition of these indexes is designed to represent the mix of particular expenses incurred by SDG&E in its operation. The results of DRI's analysis indicate that SDG&E's operation and maintenance costs have historically escalated and will continue to escalate at rates different from the national average price measures. Company operation and maintenance costs escalation over the 1982-1986 interval on a compound annual rate basis is forecasted to be 1.0 percentage point higher than the Producer Price Index for finished goods (PPI) and .4 percentage points higher per year than the gross national product (GNP) deflator.

TABLE 2

COMPARISON OF SDG&E AND STAFF ESCALATION FACTORS

	LABOR		NONLABOR	
Year	Staff	SDG&E	Staff	SDG&E*
1982	8.5%	8.5%	2.8%	4.9%
1983	7.0	7.0	1.8	1.9
1984	3.9	3.3	4.9	5.9
1985	4.6	4.5	5.7	6.2

*SDG&E develops factors for specific expense areas; figures shown represent a composite of those factors.

McNeill, explaining the method used by DRI to derive SDG&E's specific nonlabor escalation forecast, stated that SDG&E first provided five years of data on company expenditures by Federal Energy Regulatory Commission (FERC) accounts. DRI broke down these expenses into major expense categories and then separated out the operation and maintenance portions. Using the actual FERC account information provided by SDG&E, DRI then constructed composite cost indexes which indicated the escalation of the basic cost elements within each of the accounts. The weightings used for each FERC account were based on actual expenditures of SDG&E. Equal weightings were assumed below the level of FERC accounts because SDG&E does not have the records available and, in fact, knows of no utility that keeps such records.

Mark R. Loy, a staff witness for the Revenue Requirements Division, provided the staff estimates of escalation factors. For his nonlabor estimate Loy used the same method that was adopted by the Commission in the 1982 Pacific Gas & Electric Company (PG&E) Rate Case, D.93887 dated December 30, 1981 in A.60153. That method is referred to as the Modified Producer Price Index (MPPI). Loy said the only difference between the staff proposal for PG&E in 1982 and that for SDG&E in 1984 is that the physical weights assigned to the selected PPIs have been updated from 1980-1981 using the Supplement to the Producer Prices and Price Indexes for 1981 published by the Bureau of Labor Statistics in August 1982.

Loy testified that the staff made escalation estimates and recommendations for PG&E's current 1984 test year rate case that are identical to its SDG&E recommendations. He conceded that the staff in order to make such recommendations, assumed there were no differences in the operations of the two utilities.

Loy claims that a main concern of the staff with the DRI model introduced by McNeill is that it is extremely complex and involves hundreds of equations, variables, and adjustments. He stated that at the smallest level of detail, SDG&E's method does not contain expense items or associated physical weights which are specific to SDG&E and therefore is basically a western region industry-wide formulation. Loy further disagreed with the DRI method because:

1. It arbitrarily assigns equal weight to all components within a particular expense account which is unsupported by any analyses. As these weights are aggregated into functional groups serious errors in the weighting of expense items are compounded.

2. It incorporates price indices beyond the degree of detail required consistent with the arbitrary assignment of equal weights. This increases the likelihood of double and triple accounting errors when more highly aggregated indices are incorporated.

3. It incorporates indices, i.e. coal and natural gas, which are inappropriate to general rate case proceedings.

Loy recommends that SDG&E's proposed method be rejected because the staff cannot, in a timely manner, verify results from such an immense model. Without the ability to verify results, the Commission must be completely reliant on the integrity of applicant. Also, it makes it difficult for other parties to make recommendations in rate case proceedings. He believes this violates principles of fairness because estimating methods should be available to all parties for scrutiny. For these reasons, Loy recommends that SDG&E's proposed method be rejected as unacceptable for rate case proceedings and that the Commission adopt his MPPI method as being the most reasonable and fair.

Even though the DRI method has the infirmity of equal weighting at the subaccount level to which varying escalation factors are applied, we believe it more accurately reflects SDG&E experience. The staff's generalized method is basically a measure of the inflation present in overall industrial economic activity and, as staff indicated, can be used for either PG&E or SDG&E regardless of whether there are significant differences in their operational characteristics. Loy made no analysis of how the staff method compared with SDG&E's historical experience and agreed it would be difficult to test either the DRI or staff method against historical experience.

We are sympathetic with the staff's concern that all parties should have ready access to the various escalation indexes that go into our adopted escalation factors. However, we believe that the desirability of access must be weighed against the potential accuracy and facility gained through sophisticated techniques. SDG&E and the staff should cooperate in establishing criteria to determine the validity and accuracy of proposed approaches to escalation because of the possibility that a simple, inexpensive approach may be as accurate as, or more reliable than, a more complicated computer model. We need to be able to evaluate whether any burden imposed by a complex method is out- weighed by greater accuracy in the resulting estimates of escalation.

The general rate case is not the ideal proceeding for resolving this kind of technical dispute. Our procedures cannot accommodate repeated litigation of the escalation issue to the extent that occurred in this case. Because of the large amounts of dollars affected by small changes in escalation rates, we urge the company and the staff to schedule workshops which attempt to agree on a method for deriving escalation factors. Staff should also explore whether a single approach can be consistently applied to other utilities.

As a result of these findings, we will not adopt either the DRI method or the staff's MPPI. We decline to adopt the DRI method primarily because the time required for our staff (and others) to check the utility's calculations, particularly in making the attrition year adjustments, is extensive, and because the results of the DRI's sensitivity analysis suggest that the DRI model is unnecessarily detailed. We will not adopt the staff's MPPI method because the relative weights are not directly related to SDG&E's operations.

However, we will adopt a composite index, based on the DRI model, that we believe is verifiable and representative of SDG&E's actual expenses. To accomplish this, the adopted composite has been constructed by taking the DRI weighted price indexes and aggregating them into the associated price indexes published in the DRI hardcopy issues. For example, of the seven indexes the DRI method uses for chemicals, only one, WPI06, is published in the DRI hardcopy issues. Consequently, in the adopted composite, the weights of the seven indexes are summed together and the result is assigned to the WPI06 price index. Those indexes in the DRI model for which there was no related index in the DRI hardcopy forecasts were dropped (2.21% of the total). We have removed the price index forecasts for postage. Any increases the actual postal rates should be addressed in SDG&E's attrition filing. The adopted weights and price indexes are as follows:

A.82-12-57

Adopted Nonlabor Composite Index

DRI Index	Relative Weight
CPI-U	.1925
CPIU91900	.0184
ICNBCCST	.0185
IDENCOST	.0780
JRWSSNE	.1304
WPSOP2000	.0728
WPI03	.0040
WPI057	.0249
WPI06	.0778
WPI07	.0033
WPI08	.0205
WPI09	.1761
WPI10	.1034
WPI11	.0998
WPIIND	.0391
Totals 15 Indexes	1.0000

The adopted composite index meets the requirement of availability because it incorporates price index forecasts and relative weights which are developed from accessible sources without raising problems of copyright infringement or access fees. The development of the forecasts and weights is available to all interested parties for verification, critical review, and modification. This adopted method also meets the requirement of reflecting of SDG&E's cost history by incorporating relative weights which were developed from SDG&E's actual expense accounts. In addition, our staff should be able to check calculations based on these 15 indexes within the time constraints presented by the attrition adjustment filing. Thus, the adopted composite index fairly and reasonably measures the material and service expenditures in a manner reflecting the technical sophistication of the DRI model and the practical concerns of this Commission.

Adopted Nonlabor Escalation Factors

Year	Annualized Factor	Compounded Factor
1982	3.8%	3.790%
1983	2.0%	5.883%
1984	5.13%	11.461%

Although we are adopting this composite index for this case, we would like to see equal weightings of the price indexes at the subaccount level replaced with relative weights based on SDG&E's actual purchases. Contrary to the testimony of SDG&E, staff claims such records are available, at least for SDG&E's gas department.

5.1.2. Labor Escalation Factors

SDG&E uses DRI forecasts and its contracted wage agreements to estimate its labor escalation factors. SDG&E's original factors exceed the staff's estimates; however, SDG&E amended its factors to reflect more recent DRI forecasts and, as Table 2 shows, SDG&E estimates for '84 and '85 are now below staff's. However, there is the issue of the staff policy recommendation that, for ratemaking purposes, wage increases should not exceed the increase in the cost of living as measured by the CPI-All Urban Index (CPI-U) under a base-line or neutral situation. To convince us of this, staff goes into a lengthy argument in its brief liberally sprinkled with citations to Commission and court decisions. While cost of living is an important factor in wage adjustments, Commission policy does not limit wage increases to changes in the CPI. Utilities must have the flexibility to meet their skill requirements under conditions established by applicable labor markets. Nowhere, however, in testimony or argument does it present any evidence that SDG&E does not bargain effectively with its employees, within the framework of applicable labor markets. In fact, as shown on Table 3 which is taken from Page 2-2 of staff's Exhibit 24, for the latest five years of actual data, SDG&E has done quite well against the U.S. and San Diego CPI-Us.

TABLE 3

HISTORICAL PERCENTAGE CHANGES

	1978	1979	1980	1981	1982
United States CPI-U	7.7	11.3	13.5	19.3	6.0
San Diego CPI-U	9.9	16.5	15.1	13.4	7.0
SDG&E Wages	7.0	7.0	9.5	12.4	8.5

Staff explained that its labor escalation forecasts are developed from information contained in Review of the U.S. Economy dated December 1982, and a review of SDG&E union contracts for '79 to '83, the regional trends in the consumer price indices, and industry-wide settlements for public utility labor. Staff took, for each forecast year, the DRI estimates for the CPI from DRI's optimistic, pessimistic, and control estimates and combined them using probabilities assigned by DRI into one weighted average. They then took this neutral estimate and adjusted it to correspond with the time of year when the union contract settlements would become effective.

For purposes of this proceeding we will adopt SDG&E's wage escalation factors as reasonable for developing expense estimates for 1984. For 1985, SDG&E's attrition filing should reflect 1984 actual labor increases.

5.1.3. Construction Cost Escalation

In addition to providing an analysis of escalation in operation and maintenance costs, DRI provided a projection of utility plant construction cost escalation through 1987. The cost index selected by DRI measures construction cost for a total plant, all-steam generation facility in the Pacific Region of the United States. DRI concludes that utility plant construction cost reflected in the total plant, all-steam generation index for the Pacific Region is also projected to be higher than the national price measures over the forecast interval. The increment over the 1982-87 interval on a compound annual rate basis is forecasted to be 2.3 percentage points higher than the producer price index finished goods and 1.8 percentage points higher than the GNP deflator. McNeill claimed her forecast of construction cost for utility plant and transmission distribution facilities, was a better measure of utility construction cost than the producer price index (PPI) because the DRI forecasts specific items used for utility construction rather than the PPI measure of the general economy.

We will adopt the company construction escalation factors but apply them using the staff method as explained under the rate base discussion.

5.2 Telephone Divestiture Expenses

SDG&E requests an additional $2.5 million for 1984 and $2.685 million for 1985 to cover anticipated increases in its telephone service costs due to the divestiture of The Pacific Telephone and Telegraph Company (PT&T) from The American Telephone and Telegraph Company (AT&T). The company's witness on this matter admitted that his estimate was subjective and that it would be extremely difficult for SDG&E to account for any increases due to the divestiture. In the opinion of the staff there may be little effect from the divestiture settlement on SDG&E's operations. The estimate of $2.5 million by the company for 1984 is based on a doubling of its 1981-82 costs for telephone service. The staff points out that most predictions are that basic residential charges are likely to increase while long distance charges would decrease as a result of the divestiture. Both the witness for the staff and the FEA indicated SDG&E will have additional telephone services available to it from a number of vendors offering competitive prices.

We expect the divestiture will do what it is supposed to do and that is either hold the line on telephone costs or reduce them. For instance, we note AT&T's recent proposal to reduce long distance rates. Accordingly, we will not allow the additional amounts for 1984 and 1985.

5.3 Intermediate Range Planning (IRP)

For estimating administrative and general expenses both SDG&E and the staff used 1982 recorded expenses as their base. The differences between their estimates center around the method used to predict growth over the 1982 base level and in particular involve administrative and general salaries. The company's estimate of growth for the 1984 test year over 1982 was based partially on a budgeting process it calls "IRP." This process, which the company initiated in 1982, requires cost center managers of the company to identify projects they plan for 1983 through 1985 which could cause increases or decreases in expenses from 1982 levels. These estimates are reviewed at a high administrative level in the company and duplicative or unnecessary projects are eliminated. The company uses it as a planning and budgeting tool and for estimating general rate case expenses.

Over 200 separate IRP projects were originally submitted for management review; about 85 were finally approved for inclusion in the 1984 budget. The IRP witness for SDG&E testified that, although the 85 projects were approved, managers were not given start dates for their projects and no funding commitments for the projects could be given to the managers or the Commission prior to the year 1984.

Because of the uncertainties surrounding SDG&E's proposal the staff rejected the IRP process and applied total company employee growth rates to administrative and general salaries (Account 920) for its 1984 estimates.

The IRP process may be a good management tool and might work very well but has yet to be verified. We recognize that this was SDG&E's first attempt to use a budgeting process for estimating test year A&G expenses and commend it for using this approach. But, due to the uncertainties we mentioned previously, we prefer in this rate case to adopt the staff method of estimating. We believe adoption of the staff estimates will give SDG&E the resources it needs to properly carry out administrative activities without requiring the Commission to essentially approve specific SDG&E projects.

5.4 Unforeseen Expenses

SDG&E includes what it calls "unforeseen expense" estimates in several of its production accounts. These are:

512	$ 120,000
513	360,000
517	1,400,300
553	75,000
	$1,955,300

SDG&E includes the unforeseen expense component based on the assertion that, in prior years, maintenance activities have consistently uncovered unanticipated damage which needed to be repaired. SDG&E claims that in past general rate case proceedings an unforeseen cost component has been included in the approved expenses for the various accounts. SDG&E's estimate of expenses for Account 512.2, for instance, was developed through a zero-based forecast of the maintenance activity estimated for 1984 as opposed to using trends or averages based on prior years' expenses. Zero-based forecasting assumes maintenance activities in 1984 are unique to that year and not necessarily related to previous years. However, SDG&E claims that a component for unforeseen costs based on prior years' experience is a necessary element of the zero-based maintenance account estimate.

Staff effectively excluded from its estimates all of the above estimates of SDG&E for unforeseen expenses on the grounds that they are speculative and unsupported by the record. Staff had requested detail from SDG&E in late 1982 on this matter and was told that the information in the form they requested it was not available. However, at the April 6 hearing, SDG&E put in Exhibit 14 which shows unforeseen expenses broken out by operating order number totaling $472,800 for 1980, $336,400 for 1981, and $710,600 for 1982. Staff moved to strike Exhibit 14 on the basis that it was information not provided to the staff on a timely basis. The company pled that as soon as it realized what it was the staff was asking for, it made every effort to provide the information, ergo Exhibit 14. The ALJ denied the staff motion. Staff renewed the motion in its brief.

SDG&E's witness on unforeseen expenses had considerable difficulty explaining exactly how his estimates for the expenses were made. In some cases he relied on what department managers gave him, and in one case, Account 517, the following explanation at RT:731-732 was given:

> "Q. Can you explain for me how the estimate for unforeseen expenses of $1,400,300 was developed?
>
> "A. Yes.
>
> "Generally our methodology for estimating nuclear expenses are to accept the most current forecast from Southern California Edison, apply our 20 percent ownership share to their forecast.
>
> "On top of this we add a small amount of internal nuclear oversight cost, a few engineers, and then for both internal budgeting and rate case forecasting purposes we found it necessary in the past years to apply an unforeseen cost component to our estimate in that our experience has been for the last three years that we consistently booked more cost in the nuclear accounts than was either forecasted by Edison or was authorized in rates.
>
> "The specific methodology used in this case was to analyze for the last five years, making a comparison of the forecast that Edison provided us, which was used for rate case forecasting purposes, comparing that number with what was actually booked in those years.
>
> "In the five such years, the closest we ever came to the Edison estimate was 12 percent; so we chose a 12 percent factor as being

conservatively representative of our unforeseen cost.

"We used a similar methodology in the '82 and '81 general rate cases."

We conclude from the record that SDG&E's unforeseen expense estimates are unnecessary additions to the basic estimates for the accounts involved. They will not be allowed. This makes the staff motion moot.

5.5 Employee Perquisites

WRO disputes the inclusion in revenue requirement of the expense for certain employee benefits such as educational assistance programs and cafeteria expenses. All of these were addressed by the Commission in D.93892. SDG&E in accordance with the findings and directives in that decision has, with staff oversight, included only the expenses, or the equivalent expenses, approved in that decision for ratemaking purposes. There is no need in this decision to discuss those issues again. We consider them to be res judicata.

5.6 Postage Expense (Account 903.7)

SDG&E estimates a postal increase of 2¢ or $174,500 will occur beginning in April 1984. SDG&E's witness in support of that estimate indicated she made the estimate based on a review of a mailers periodical and statements by Postmaster General Bolger that a postal increase would be effective for the first quarter of 1984. A review of the periodical used by the witness indicates the proposed increase is speculative at best. A staff witness recommended that no increase be projected and testified that for the fiscal year 82-83 estimated deficits for the post office operation have turned into surpluses. He stated that even if the postmaster general were to file for a rate increase in 1984 the chances of receiving the increase from the Postal Rate Commission and Congress would be slim in view of the surplus.

The Commission has historically used current postal rates in estimating test year revenue requirements unless it can be shown that any future increases have been approved and are definite (Southern California Gas Co. (1982) D.82-12-054 in A.61081.) As an offset to any possible increases the record shows that SDG&E has made efforts to improve the use of certain discount mailing techniques and could continue to make further improvements during 1984.

We will reject SDG&E's proposed increase as speculative and adopt the staff estimate. However, if postal rates are increased in 1985, we will allow SDG&E to reflect the effect in its 1985 attrition filing.

5.7 Administrative and General Salaries (Account 920)

Both SDG&E and the staff used the 1982 recorded expenses in this account as the base for the test year. The differences between the company and the staff center on the method used to predict growth over the 1982 base level which has been discussed under Section 5.3. We will adopt the staff estimate for Account 920.

5.8 Office Supplies and Expenses (Account 921)

Both SDG&E and the staff used six months through June 1982 recorded expenses annualized to estimate the base for account 921. Again, the company used its IRP estimating procedures for this account. Staff excluded management audit expenses from the account; as discussed elsewhere we adopt that decision. Staff's annualized figures also exclude amounts associated with several public relations and lobbying activities in conformance with our ratemaking policies. We will adopt the staff estimates for this account.

5.9 Administrative Expenses Transferred (Account 922)

This account represents the capital portions of Accounts 920, 921, and 926. SDG&E conceded that the staff's percentages used to derive the expenses for this account are based on the most recent data and should be adopted. There is a difference in capitalization of $635,300, the staff being lower than SDG&E. The reason for this is that since Account 922 is a function of Accounts 920, 921 and to a limited extent Account 926, differences in those three accounts between the company and staff estimates carry into the amount to be capitalized. Because we are adopting the staff amounts for those three accounts, we will also adopt the staff estimates for Account 922, with the exception of the adjustment which is made in Account 926 as a result of our not adopting the staff pension fund penalty provision.

5.10. Consultant Fees (Account 923)

The difference in the estimates of the company and the staff for this account total $1,023,400 for the electric department and $323,500 for the gas department. SDG&E used nine months of 1982 recorded experience annualized to arrive at its base for this account. The staff averaged recorded expenses for 1978 through September 1982 annualized to arrive at its base. The staff did not normalize its base figures, that is, make any adjustment for inflation from '78 through '82.

The record shows that the actual expenditures for SDG&E for 1982 were $315,000 less than the 9-month annualized figure of $2,239,000 used by the company. Following are the expenditures in nominal dollars for this account for the years 1978 through 1982:

1978	1979	1980	1981	1982
$1,083,700	$1,113,500	$677,300	$1,052,500	$1,915,000

SDG&E is conducting a management audit on order of the Commission on which it estimates it will spend $252,000 in 1984. SDG&E claims this amount should also be included in the 1984 outside services expense estimates. However, that audit remains uncompleted.

The staff recommends that, consistent with Commission practice, expenses of the audit should be booked to a deferred account pending reimbursement upon Commission evaluation of the audit results. (Southern California Edison Company (1982) D.82-12-055 in A.61138.) Staff also recommends that SDG&E's IRP project estimates not be included in this account.

We will accept the staff's recommendation to delete the management audit and the IRP funds from estimates for this account; and we accept the staff's estimate which is based on averaging five years, 1978 to 1982, except that, we will escalate actual figures for those years to 1984.

5.11 Staff's Proposed Pension Fund Penalty (Account 926)

Staff proposes a penalty for what it claims to be SDG&E's poor pension fund performance in recent years. The specific accounts to which this penalty would apply are Accounts 926 in both the electric and gas departments. The total recommended penalty would be applied as a decrease of $799,200 in expense allowances.

Pension cost to SDG&E, and hence the ratepayers is generally dependent on two factors. First, the number of employees SDG&E has and their wages, and second, the income from the investments made by SDG&E management of the Fund's capital. Staff claims that SDG&E's pension fund performance during the past few years has resulted in significantly lower rates of return than other comparable investment funds have achieved. Therefore, as a penalty and an incentive for better performance, staff made a one percentage point downward adjustment in SDG&E's normal cost rate chargeable for the first two quarters of the test year 1984.

The staff witness used the performance of the Becker Large Plans (Becker) as a benchmark for SDG&E's performance during the year 1977 to 1981. Becker is limited to funds with assets of over $100 million; SDG&E's plan has total assets of less than $100 million. In making his comparison the staff witness made an error in reporting the performance of Becker in the year 1977 which overstated Becker's performance by about one percentage point. Taking that error into account puts SDG&E's performance virtually on a par with Becker. The staff witness also conceded that San Diego's performance exceeded the Becker performance for 1982. Finally, at RT. 3139, the staff witness, in assessing the adjustments which were made to his information as a result of cross-examination, conceded the following:

> "Well, as I said near the end of yesterday, had I had all that information, it certainly would have affected my judgment as to what the penalty ought to be if indeed there was a penalty."

It concerns us that the staff is proposing a penalty without offering any recommendations on how SDG&E should improve its performance. At RT. 3142-43 the following exchange between the SDG&E counsel and staff witness Crommie took place:

> "Q. Are you proposing any further changes in SDG&E's pension fund management?
>
> "A. No.
>
> "That's a rather difficult area for me to enter into.
>
> "I'm not recommending or telling you how to manage the fund in any way or what manager to select.
>
> "I'm merely looking at evidence, or, if you will, the published performance of what you are doing and just making recommendations based on that, without in any way intruding into the actual management, telling you how to do it, just looking at results and judging results.
>
> "I have no desire or wish to be involved in the actual operation of the fund.
>
> "Q. Well, you would agree with me, would you not, that SDG&E in 1980 or 1981 made some changes in its pension fund management that have produced good results?

"A. "That's true.

"Yes, I would agree.

"Q. "And as I understand your answer, you're not specifically recommending any further changes?

"A. "No, I'm not.

"In fact, if you continue the way you are doing, you are doing excellent."

The staff witness went on to confirm again that much of the evidence that had now been put before him had not been considered.

We will not adopt the staff's recommended pension penalty fund.

5.12 <u>Executive Physical Examinations (Account 926)</u>

In D.93892, SDG&E's 1982 rate case, the Commission disallowed $39,200 for executive physical examinations. Noting that ratepayers were currently paying for two health programs which provide physical examinations, the Commission could see no reason for the ratepayers to bear the additional expense requested by SDG&E for special executive physical examinations.

In this proceeding SDG&E has reduced its estimate to $8,000 for the same purpose. SDG&E requires certain management employees, for management purposes of continuity and administrative facility, to undergo annual physical examinations. These employees are allowed to opt for four different health plans, only two of which offer free annual checkups. Executives who choose the two health plans not providing checkups must take physical examinations as required by their employment at SDG&E.

The staff claims this is an extra benefit not available to other types of employees at SDG&E and that ratepayers should not bear the cost of an election made by SDG&E's higher paid employees of which health plan suits them.

The situation in this proceeding is different from SDG&E's 1982 proceeding where SDG&E attempted to have approved $39,200 for physicals it required of its management employees and paid for regardless of the plan they selected. What SDG&E has done in this case is to eliminate the cost of special physicals it pays for those employees under the plans that provide free physicals. It has included only $8,000 to pay for the physicals it requires of those employees under plans that do not provide free physical examinations.

We will allow SDG&E's proposed expense. Management should have the discretion of requiring special physical examinations of its top-level management employees for administrative purposes. It is reasonable for the employees to choose a health plan which they believe best meets their needs. If the health plans chosen do not provide free physical examinations, but such examinations are required by the company for administrative purposes, that is a legitimate expense.

5.13 Pensions and Benefits (Account 926)

The major portion of the differences between SDG&E and the staff estimates for this account are attributable to issues involving employee growth and wage escalation factors which have been discussed and decided under certain other accounts throughout this decision. Staff and SDG&E would use the identical expense figures for certain pension and benefit items if they had come to a resolution of issues concerning escalation and employee growth. This account also involves the above discussions concerning annual executive physical examinations and staff's proposed penalty for SDG&E's alleged poor pension fund performance in recent years. For purposes of this decision we will adopt an estimate for Account 926 (unescalated) of $24,967,600.

5.14 <u>Association Dues and Expenses (Account 930)</u>

SDG&E participates in activities involving Edison Electric Institute (EEI) and the American Gas Association (AGA). SDG&E is requesting for test year 1984 dues to EEI of $317,900 and to AGA of $108,900. Staff has deleted both of these items from its estimates. Staff did this in accordance with D.93892 in SDG&E's 1982 rate case (mimeo pp. 136-138). For the same reasons stated there, we will disallow the expenses in this proceeding. We put SDG&E on notice that we will not allow such expenses in any future rate case unless fresh and convincing evidence is presented showing the benefits to the ratepayers of such expenses.

5.15 <u>Stock and Debt Securities Expense (Account 930)</u>

For estimating this account, SDG&E used 1981 recorded expenses as a base. The staff used a trend of 1977 through 1981. The following figures show the nominal dollars of expense for this account for 1979 through 1982:

1979	1980	1981	1982
$818,000	$729,000	$823,000	$1,104,000

The 1982 figure according to staff includes two extraordinary expenses and therefore is not representative. Staff considered the account to be relatively stable, except for 1982, and trended the account into 1984. SDG&E also included approximately $90,000 in the account as the part of its TRP process. The staff estimate is a better reflection of the probable expense for this account in 1984 and will be adopted.

5.16 <u>Shareholder Reports Expense (Account 930)</u>

For estimating this account SDG&E escalated its 1981 recorded expense to test year 1984. Staff used a five-year average of 1978-82 for its estimate. The record shows that 1981 was unusually high. SDG&E spent $225,000 for preparation and distribution of the report in 1981 and $137,000 in 1982. SDG&E claims that staff, in making its estimate, did not apply an escalation factor. We will accept staff's method as being more reasonable. However, its estimate will be adjusted to include escalation factors adopted elsewhere in this decision.

5.17 Bank Fees (Account 930)

SDG&E normally keeps some excess funds on deposit in the bank to avoid transaction fees. Staff removed the excess funds from working cash allowance which is included in rate base, because staff calculated that payment of fees was a lesser cost alternative. Staff's approach attempts to minimize revenues for ratemaking purposes; it does this by arbitrarily removing two-thirds of the balance required to avoid all bank charges from rate base. In lieu, staff includes bank fees in administrative and general expense to replace the rate base deduction. SDG&E stipulated to staff's method but disagrees on what amount should be included for test year 1984. SDG&E estimates $556,200 and staff $411,000. The difference is primarily due to special escalation estimates developed for the account, SDG&E estimating a 35% rate and staff 15%. Staff's estimate is more reasonable and will be adopted.

5.18 Research, Development, and Demonstration (Account 930)

SDG&E's revised request for its RD&D programs for 1984 is $15.1 million. With a few exceptions, staff supported SDG&E's request. We will authorize the utility's request except for the items discussed in the following paragraphs. We set forth SDG&E's 1984 request next to the program's title.

Electric Vehicle Development ($36,400). This project offers little prospect of direct benefit to SDG&E's ratepayers. Vehicle research is more appropriately funded by other entities.

Blythe Site ($308,000). This project does not appear to be RD&D as we defined it in D.82-12-005. SDG&E has stated its intent to develop commercial facilities on the Blythe site. Therefore, this project is more appropriately treated, for ratemaking purposes, in conjunction with our adopted policy on the Blythe site discussed later in this decision.

Advanced Technologies Blanket ($74,800). We will not authorize funds for this category because it appears to include studies on commercial projects. Some items are only vaguely defined or do not appear to offer ratepayer benefits.

We find it is reasonable to direct SDG&E to comply with staff's recommendations that:

In future rate cases, SDG&E provide RD&D estimates in constant year dollars for labor vs. nonlabor and other.

SDG&E's future filings and April 15 annual RD&D report be in the format shown in Appendix D of staff's Exhibit 45 on RD&D including the information requested by staff on pages 2 and 3 of that exhibit, consistent with D.82-12-005.

We will authorize SDG&E to provide funding for the Electric Power Research Institute (EPRI) at the level established by EPRI's actual billing to SDG&E for 1983, which is $2,514,000. This is consistent with the treatment of EPRI expenses allowed for PG&E and SCE in recent general rate case decisions.

With these changes, our authorization for RD&D is $14,613,000 for 1984.

6. Electric Department Expenses

6.1 Boiler Plant Maintenance (Account 512)

Estimates for this account are SDG&E $5,631,800; Staff $4,764,600; difference $867,200.

The difference is due to two factors. Differences in forecasting methods accounts for a $747,200 difference in Subaccount 512.1 (Routine Boiler Maintenance); SDG&E's unforeseen expense factor accounts for a $120,000 difference in Subaccount 512.2 (Boiler Overhauls). The latter factor will not be allowed as we concluded in our discussion of unforeseen expenses. SDG&E used a 10-year trend in estimating Subaccount 512.1. SDG&E claims the units involved with the maintenance expense are 23 years old and the average age is increasing. In addition the units are subject to increased cycling, that is, starting and stopping the units for service, because SDG&E is diversifying its resources and using substantially increased amounts of nuclear and purchased power. SDG&E claims this increases the stress on the plants and leads to additional maintenance. Also, SDG&E states that the quality of oil burned in the units has been degrading and that also requires additional maintenance.

For its Subaccount 512.3 estimate the staff averaged 1979, '80, and '81 figures. The staff essentially shows no growth by using those three years whereas the SDG&E method indicates an annual growth rate of about 5-1/2% exclusive of inflation.

Expenses for Account 512 for '77 through '82 at '82 dollar levels are as follows:

1977	1978	1979	1980	1981	1982
$3,747,500	$3,689,900	$4,914,200	$5,254,300	$4,420,400	$4,798,900

It appears, from the above figures, that, at least in the last four years, there has been somewhat of a downward trend for this account. We will agree with the staff that their estimate is the more reasonable one and it will be adopted.

6.2 Electric Plant Turbine Maintenance (Accounts 513 and 553)

The issues in these two accounts are similar to those in Account 512. The company has included an amount for unforeseen expenses in each of the accounts, $360,000 in Subaccount 513.2 (Turbine Overhauls) and $75,000 in Subaccount 553.2 (Gas Turbine Overhauls); the remaining differences are due to the manner in which the company and staff forecasted their estimates for Subaccounts 513.1 (Routine Turbine Maintenance) and 553.1 (Routine Gas Turbine Maintenance). A summary of the two estimates for 1984 shows:

	SDG&E	Staff
Account 513	$4,295,800	$3,770,000
Account 553	2,667,000	2,263,300

Recorded nominal expenses for the two accounts as shown in Exhibit 3, Chapter 3 are:

	Account 513	Account 553
1977	$1,974,300	$ 881,600
1978	2,047,600	925,800
1979	2,853,700	1,200,500
1980	3,361,300	2,271,500
1981	2,829,500	2,201,100

SDG&E claims that Account 553 can be expected to show real growth because of the increase in the number of hours of operation of base-loaded gas turbines. They point out that in the last six years the amount of generation from gas turbines has quadrupled, and that the amount of maintenance is proportional to the hours of operations. It is true that Account 553 from 1977 to 1981 did show real growth in nominal dollars but it is also true that it dropped off in 1981 over 1980. Account 513 shows the same trend.

We will again accept the staff estimates as being more reasonable for forecasting purposes and exclude the unforeseen expense estimates of the company for the reasons discussed in Section 5.4 of this decision.

6.3 Supervision and Engineering (Account 517)

The difference between the SDG&E and staff estimates for this account are entirely due to the company estimate of unforeseen expenses of $1,400,300. We will not allow unforeseen expenses in this account and, therefore, accept the staff estimate as reasonable for 1984.

6.4 SONGS Sleeving Expense (Account 524)

SDG&E has incurred a total expense of $14,572,000 for the resleeving of the SONGS 1 steam generator unit. About four times that amount was borne by the co-operator Southern California Edison Company (Edison). This matter was still pending from the standpoint of ratemaking treatment when we issued D.93892 in SDG&E's 1982 general rate case. In that decision we allowed SDG&E to capitalize a certain amount for the resleeving pending a later determination as to the manner in which Edison's rates would reflect the expenses. By D.82-12-055 in A.61138 of Edison, the Commission provided that Edison should recover costs of the project as an extraordinary maintenance expense. We provided for a 4-year amortization of those expenses and held that we would not consider the sleeving project a capital expenditure because it did not extend the useful operating life, capacity, or efficiency of the steam generator. We thus modified amounts charged to rate base and depreciation expense consistent with the operating expense holding. Under the treatment we gave SDG&E's portion of the expense in D.93892, SDG&E has received revenues as of the end of year 1983 of approximately $7,034,000 as calculated by the staff. Deducting that amount from the project costs of $14,572,000 the staff calculates there is $7,538,000 remaining to be recovered. The staff accountant recommends the remaining amount be amortized over four years commencing with test year 1984. Under that approach the total revenue requirement would amount to $1,884,500 per year.

SDG&E proposes an amortization over two years of $10,133,000 beginning in 1984. Its position is that the 4-year amortization period started in 1982. Also, SDG&E's estimate of the amount left to write off is larger than staff's because SDG&E claims, and mistakenly so, that staff has not taken into account federal income taxes.

A staff engineer presents a third proposal for recovery of the expenses. He removed $14,745,000 from the rate base with appropriate adjustments to the depreciation reserve. Using a 4-year amortization period he would expense $3,643,000 per year in Account 524. However total revenues received as of the end of the year 1983 were calculated by him to be $7,034,000. He credits that amount against the test year 1984 revenue requirement which equals $7,286,000, the sum of the 1983 and 1984 revenue requirements. He thus recommends an Account 524 test year '84 expense of $252,000 and $3,643,000 for 1985 and 1986. Under his scheme SDG&E would be made whole at the end of the year 1986, the same time as Edison.

We will adopt a variation of the staff engineer's proposal. Instead of the 4-year write-off commencing with test year '84 we will write off the $7,538,000 in two years, 1984 and 1985. We do this in recognition of the fact that in 1982 and 1983 ratepayers generated $7,034,000 toward the write-off. Under the scheme we adopt, ratepayers in 1984 and 1985 will write off a similar amount, $7,538,000.

Staff points out in its brief that if the Commission were to adopt either of the staff approaches there are two key considerations to take action on. First, staff recommends that the sleeving expense should be treated as an extraordinary expense for attrition purposes. This is reasonable and we will do so. Second, staff believes the sleeving expense should be made subject to refund pending the outcome of the Commission's investigation into the reasonableness of Edison's pursuit of litigation against the SONGS contractor allegedly responsible for the defects which required the sleeving project. This recommendation is reasonable and will be adopted. SDG&E is also a plaintiff in the litigation. As with Edison we expect SDG&E pursue the litigation in good faith in order to ensure that the ratepayers' interests are adequately protected.

There are two further matters. SDG&E claims that it has paid ad valorem taxes on the rate base portion of the capitalized amount for the resleeving project which will now be removed from rate-base. Also it claims there are equivalent income tax payments which should be recouped because the Internal Revenue Service (IRS) has required that SDG&E capitalize the expense for tax purposes. The record shows that SDG&E has not yet filed its 1982 Federal Income Tax return nor, of course, its 1983 return. Therefore, it still has an opportunity to reflect this Commission's ratemaking decision in those returns and place the sleeving issue before the IRS for litigation, if the IRS continues to insist that it be capitalized. We will expect SDG&E to make a good faith effort to recover the ad valorem taxes as well as a good faith effort in its litigation before the IRS. Final disposition of the ad valorem tax issue can be considered in SDG&E's 1986 general rate case.

6.5 Non-ECAC Fuel Expense (Account 518)

SDG&E requests $2,626,000 for spent nuclear fuel expenses for 1984. Staff has not allowed anything for this expense because it believes the expense should be recovered through SDG&E's Energy Cost

Adjustment Clause (ECAC). SDG&E does not object to the staff recommendation provided the Commission orders SDG&E to pursue recovery through the ECAC process and not the general rate case. Staff testified that a portion of spent nuclear fuel costs are directly attributable to electric production and SONGS 1. This production is subject to a mils per kilogram rate determined under federal law (Nuclear Waste Policy Act of 1982, Public Law 97-425, January 1983). The Department of Energy's rulemaking under the new law, requires payment for the disposition of spent nuclear fuel to begin in 1983. The cost will be incurred currently and, therefore, the use of the accrual method with a reserve is inappropriate. Costs that are a function of energy produced (mils per kilowatt hour) are more properly addressed in an ECAC proceeding. We will adopt the staff's recommendation.

6.6 <u>Wheeling Expense (Account 565)</u>

When we issued D.93892 in December 1981 in SDG&E's 1982 rate case there were some fixed capacity wheeling contracts as yet unsigned. Because these contracts benefit ratepayers we authorized SDG&E to carry on its books the fixed costs of the contracts which were not included in base rates for 1982 and 1983. We stated that these costs would be recoverable in SDG&E's next general rate case if found reasonable. In this proceeding SDG&E has included charges stemming from the Arizona Public Service West Wing - Palo Verde contract, a contract which was executed subsequent to the creation of the deferred account by D.93892. The inclusion of the fixed costs of that contract are appropriate under the treatment we approved in D.93892.

However, SDG&E has interpreted the Commission's findings in D.93892 as being applicable to all of its wheeling contract expenses, even those which were included on an estimated basis for the test years 1982 and 1983 by D.93892. That was not our intention. We only intended to eliminate the unfairness of not including contracts which were imminent when we signed D.93892, contracts which were obviously going to be applicable to the rate years 1982 and 1983. The only thing not known was what those expenses would be and what contracts would be signed. SDG&E has included in the balancing account approximately $659,200, including interest, for amortization of wheeling contract expenses for contracts which were executed prior to the issuance of D.93892 in the mistaken belief that the Commission intended that those contracts were to be included in the balancing account as well as contracts unsigned as of the issuance of D.93892. That was not our intent and they will not be allowed.

The staff has disallowed some $50,000 of interest on the balancing account which SDG&E claims should be calculated based on DRI forecasts of interest rates plus 300 basis points. It was our intention in D.93892 that any calculations of interest on the special balancing account would be calculated in the same way as other balancing accounts, that is, using the 90-day commercial paper rate. (Mimeo., p. 110.) Therefore, we will not allow that expense either. That brings the total adjustment to SDG&E's Account 565 estimate to $709,200.

6.7 <u>Miscellaneous Distribution Expenses (Account 588)</u>

There are two differences between SDG&E and staff estimates for this account. One is growth, $84,300, and the other is Distribution Facilities Information System (DFIS) costs of $421,000.

DFIS is an automated distribution facilities mapping system and engineering data base which will replace SDG&E's hand mapping operation. It can also be used for system design activities, engineering planning, internal cost accounting, cost estimations, and valuations. Staff agrees with SDG&E that DFIS is a worthwhile, cost-efficient undertaking which will ultimately benefit ratepayers by improving service and reducing costs. Staff and SDG&E, however, differ on the amount of allowance for conversion costs and productivity savings that should be included in test year '84.

Fairly substantial allowances were included in 1982 and 1983 for the planning and implementation of DFIS. However, SDG&E management determined that further studies were required prior to the commitment of funds to the project and, therefore, it did not get off to the start expected in 1982. Staff believes that SDG&E has overestimated the costs of DFIS conversion chargeable to the Electric Department by $350,000 and has understated the productivity savings by $71,000.

In making its estimate for the DFIS conversion costs SDG&E obtained quotations from three conversion vendors. These three quotations ranged between $2,000,000 and $8,000,000. The wide range was the result of vendors being given only general specifications for the project and, therefore their responses covered different scopes of work. SDG&E averaged all of the quotes to arrive at an estimated conversion cost of about $5,000,000. On the other hand, the staff averaged the quotation of the two lowest vendors and came up with an estimate for conversion of about $1.4 million less that SDG&E. Amortizing this difference over a 4-year conversion period amounts to a $350,000 per year difference between the staff and SDG&E estimates. SDG&E conceded that it averaged the three vendors for modeling purposes only and felt that some actual conversion bids would be available by the time of the update hearings in September. They were not.

The record shows that we authorized $3,862,000 for 1982 and $4,445,000 for 1983 for this project. However, the company only spent $1,269,000 of the 1982 funds because of its deferral of the DFIS implementation. We will adopt the staff's estimate for the conversion and eliminate $350,000 for 1984 and 1985 from the company estimates.

The primary reason for the difference of $71,000 for productivity savings between SDG&E and the staff estimates is due to estimated personnel reductions. SDG&E claims that because DFIS will be diversified throughout SDG&E's system it will be unable to save whole person-years and, in fact, SDG&E will not be able to estimate what the savings will be for a few years hence. The staff, on the other hand, claims that the total personnel in the various departments affected are so large that there should be no problem reducing the force presently working on the projects that will be replaced by DEIS. We will adopt the staff estimate of $71,000 in productivity savings.

SDG&E's estimate of the growth for Account 588 was based on the growth rate of a total of 17 electrical distribution accounts. The difference in growth estimates between SDG&E and the staff account for the $84,300 difference previously mentioned. The growth rate for this account has been adjusted downward because the mapping and records activities for the distribution system are correlated to customer growth and there has been a reduction in the customer growth rate. Therefore, SDG&E decreased the rate of growth between 1981 and 1984. Staff used the same 1981 base as SDG&E but applied no annual growth. Staff claims that it recognizes growth by adding the company estimated new programs and projects to the 1981 base. The company witness for this account claims that he adjusted 1981 recorded figures to remove unusual and nonrecurring expenditures. However, he could not explain why 1981 recorded expense was $2,308,500 and 1980 was $1,441,700. In 1982 the recorded figure was $3,931,000. His total estimate for 1984 at 1981 dollars was $5,685,800 and the staff's is $5,180,500, both include DEIS costs. We will accept the staff estimate as being more reasonable.

6.3 Maintenance of Overhead Lines (Account 593)

There is a difference of $333,700 between SDG&E and the staff estimates for this account; it is attributable to different estimates of the growth rate. SDG&E used a trend of eight years (1972-1981) eliminating 1976 and 1977 because of substantial layoffs made during those years. SDG&E claims it had a 25% increase in tree trimming costs in 1982 over 1981. Tree trimming costs are a substantial part of Account 593.

The staff used an average of the years 1979, 1980 and 1981 to develop its estimate for Account 593. SDG&E claims this would not reflect the increase in tree trimming expenses in 1982 which came partially because it started using two contractors, whereas, previously it had only used one. ~~The decision to use two contractors~~ followed the staff's suggestion in SDG&E's 1982 test year rate case. In D.93892, the Commission gave SDG&E a productivity improvement target which it claims it has met.

There are substantial increases in Account 593 which are not clearly explained by the record. The following are the actual figures for 1978-1981, and an estimate for 1982 made by SDG&E.

1978	1979	1980	1981	Estimated 1982
$5,021,000	$5,961,000	$6,491,000	$7,143,000	$10,733,000

The company and staff estimates for 1984 at the 1981 dollar level are $10,640,500 and $10,307,400, respectively. We note in D.93892, (mimeo pp. 112 and 113) that the company estimate for 1982 was $9,797,000 and the staff estimate $8,736,000. It appears the Commission adopted a figure for 1982 of about $8,856,000.

The company's estimate for 1982 of $10,733,000 at 1982 dollars compares with its estimate for 1984 of $10,640,500 at the 1981 dollar level. We believe the estimated 1982 figure which is a

50% increase over 1981, is excessive. Unfortunately, the record does not disclose what the actual 1982 figure was. We will adopt the staff estimate of $10,307,400 (unescalated) for this account for 1984.

In its brief WRO cites what it considers a problem for SDG&E of other utilities using the distribution facilities (poles, etc.) of SDG&E and causing increased expenses for SDG&E. The record is unclear on whether the problem is significant. We will expect SDG&E to address this matter in its next major rate case; if there is a significant expense involved, it should take steps to adjust the charges that it makes to other utilities for the use of its facilities thereby relieving SDG&E ratepayers from carrying such expenses.

7. Gas Department Expenses - General

SDG&E and the staff reached a full stipulation with respect to base estimates of test year gas supply, gas storage and gas transmission expenses. This stipulation was derived by compromising one half of the differences between the company's estimates and the staff's. Both parties want the Commission to note that the stipulations in these areas do not constitute resolutions of the different methods used to develop expense estimates. We so note.

7.1 Supervision and Engineering (Account 870)

Two differences make up the $5,100 at issue between SDG&E and the staff for Account 870. Although there are very few dollars involved, the question of methods used to estimate expenses needs to be resolved.

$2,200 of the $5,100 difference is due to different allowances by SDG&E and the staff of salary and overhead expenses for an additional draftsman in a mapping group. The company and the staff were approximately $10,000 per year apart in estimating the total cost of the draftsman. Since 20% of the draftsman's salary goes to Account 820, the difference between the company and the staff is $2,200. The company witness on this matter did not know whether the salary estimated by the company would actually be paid to the draftsman. On the other hand, the staff used its method of a third step of a six-step salary range in estimating the salary for the employee; this is the standard staff method for calculating all new positions. The staff method for calculating the salary seems more sound than the company's and will be adopted.

The other $2,900 of the $5,100 differences is associated with amortization of two studies, the gas load profile and the gas planning weather studies, both of which were completed in 1981. As we discussed under Account 565 in the electric department expenses, the company appears to have estimated the $2,900 in the same way it estimates the so-called unforeseen expenses. For this particular account they prefer to call them unforecastible extraordinary expenses. Whatever they are, we view them as retroactive ratemaking and we will disallow them. The company states in its brief that if its method is found to be objectionable, it should be instructed in the future to include these expenses in its normal trending methods. We suggest that is a more sound approach.

We adopt the staff's estimate of $1,243,500 (unescalated) for Account 870.

7.2 Customer Installation Expense (Account 879)

The difference between SDG&E and the staff for this account is $80,400. The company and the staff used similar methods for nonlabor expense estimating but different data points; this appears to be the sole reason for the $80,400 difference. Staff stated it had one more year of data and therefore its estimate reflects current conditions. We will adopt the staff's estimate.

7.3 Other Operations Expense (Account 880)

The difference between the company and the staff for this Account is $8,900, of which $1,900 is the result of the methods used for estimating the salary of a new clerk. As we did under Account

870 discussed above (Section 7-1), we will accept the staff's estimate.

The remaining $7,000 difference represents a disagreement between the company and the staff concerning factors used to de-escalate historical data from 1981 back to 1974. In order to compare historical data on a common dollar basis, SDG&E de-escalated recorded data to 1974 dollars. The staff did not agree with the de-escalation factors used by the company; staff used different escalation factors and obtained a different result. We will use the company method because we have adopted their nonlabor escalation factors. Therefore, the final amount we will adopt for Account 880 is the staff's estimate of $1,134,000 increased by $7,000 for a total of $1,141,000.

8. Steam Department Operating Expenses

There were no issues which arose concerning estimates by the company and staff for test year '84 Steam Department operating expenses.

9. Ad Valorem Taxes

Staff adopted SDG&E's estimated test year '84 average ad valorem tax rate as being reasonable. Any differences between the company and staff are the results of differing estimates for plant-in-service, depreciation reserve, and plant held for future use. We will adjust the estimates of ad valorem taxes to match the adopted estimates for those factors.

10. Payroll and Miscellaneous Taxes

The differences between SDG&E and the staff for these taxes result from different estimates of employee growth and wage escalation. Neither party reflected the effect of recently-enacted FICA increases and a state unemployment insurance rate change. These items were updated in the September 1983 hearing; we also take note of The Federal Insurance Contributions Act change in tax base to $37,800 effective January 1, 1984.

11. <u>Income Taxes</u>

SDG&E and staff are generally in agreement on the methods for determining income taxes. Differences in the estimates are due primarily to differences in taxable income from results of operations calculations.

One area of uncertainty is the Tax Equity and Fiscal Responsibility Act of 1982 (TEFRA). TEFRA amended the rules regarding the treatment of construction period interest and ad valorem taxes. Portions of these expenses must now be capitalized and deducted over a ten-year amortization period. SDG&E made an estimate of the effects of TEFRA in its calculations. The staff made no estimates of the effects due to the uncertainty surrounding the definitions used in certain parts of the act in the hope that the Department of Treasury and the IRS would provide guidelines. There is no question that these regulations will affect SDG&E's tax expense for test year 1984. We will expect SDG&E to make an appropriate filing for review by the staff and the Commission as soon as guidelines are available. In the meantime, we will not consider the effect of TEFRA in this decision.

12. <u>Depreciation</u>

There are no differences between SDG&E and staff on the methods for deriving depreciation and amortization expenses. Differences which exist are due to differences in estimates of utility plant for the test year. There are, however, two matters which require discussion concerning the gross plant estimates. The first is the inclusion by the SDG&E in its original estimates of amounts associated with nuclear generating station decommissioning expenses in its depreciation estimate. The staff included nothing for this. By D.83-04-013 in OII 86 concerning nuclear decommissioning, the Commission left a number of ratemaking issues open. SDG&E, as a result, filed Exhibit 17, which recommended that the staff's adjustment to depreciation expense be adopted with a deferral of ratemaking recovery of any OII 86 related expenses to SDG&E's test year 1986 general rate case. The staff concurred with that approach and we will adopt it. There is also the issue of the SONGS 1 sleeving expenses which we have discussed elsewhere in this decision. We will make an appropriate adjustment to rate base to correspond to our holding concerning the sleeving expenses.

The FEA took exception to a technique used by SDG&E and staff known as quantifying added uncertainties (QAU). According to witness Maginnis for FEA, the quantifying added uncertainties technique relies too heavily on SDG&E's judgment regarding future events which might affect the remaining life of plant. Maginnis stated that he would not object to mathematical construction of a statistical formula for taking care of uncertainties provided the factors used in the formula were based on known changes whose effects could be calculated with some precision. He believes the company has failed to provide a reasoned determination of such values and, in fact, has made no demonstration of their accuracy but simply uses judgment.

The company and the staff used the Commission's standard practice for determining depreciation expense for this proceeding. The staff employed the judgment of its own expert engineers to verify company judgment, and they were in agreement as to the reasonableness of the parameters used to determine depreciation which is based on the straight-line-remaining-life method. The company and the staff have used the same methods employed for the 1982 test year general rate case. We believe this provides an equitable allocation of depreciation expense to those ratepayers who benefit from the plant involved. We find there is no merit to FEA's suggestion that the quantifying added uncertainties method is not appropriate for 1984.

13. Rate Base

The following are the issues in this proceeding concerning rate base.

1. Plant estimates.
2. SONGS common plant.
3. SONGS sleeving.
4. Distribution Facilities Information System (DFIS).
5. Property held for future use (PHFU)
6. Free footage allowance.
7. Materials and Supplies.
8. Working Cash.
9. The Sundesert (Blythe) site.

13.1 Plant Estimates

SDG&E estimated its 1983 beginning-of-year (BOY) plant by taking its 1981 year-end plant plus an estimate of 1982 additions. The staff used the actual 1982 end-of-year recorded plant for its estimate of 1983 BOY plant. SDG&E claims the staff method leaves about $27,000,000 of 1982 recorded end-of-year plant not picked up by the staff because it had not been closed to the plant accounts at the end of 1982. The company claims that the expenditures had been incurred but some of the projects had not been closed to plant at the end of 1982. A company witness stated that half of the $27,000,000 worth of capital expenditures had been closed to plant account before hearings in this proceeding began in March 1983. He also indicated that all of the plant would close in 1983 and should be included in 1984 BOY plant. After arriving at its 1983 BOY plant, SDG&E used its construction budget for 1983 to estimate additions by project. This brought the plant to BOY 1984. SDG&E used the same method to determine the end-of-year 1984 plant by adding to plant its estimated construction budget and retiring the estimated plant that would be retired during the year 1984.

The staff used a different approach than the company to arrive at additions for 1983 and 1984. The staff claims that by using the end of 1982 actual recorded plant as its beginning of year '83, its estimates are more precise because it is using actual book figures. It then estimates what will come into plant in 1983 including that which SDG&E claims should have been added at the end of 1982 as being not yet distributed to the plant accounts when the books were closed at the end of 1982. Staff claims this step is not necessary because by averaging the additions to plant for several years it comes up with a reasonable amount to be added in 1983 and 1984. To do this, the staff used a three-year average of 1980, 1981, and 1982 recorded additions and escalated them to 1982 dollars using staff indices. This was then escalated to 1983 and 1984, respectively. However, in one category, a large one, SDG&E claims staff used a different and understated approach by employing an average for the years 1979 to 1982 instead of using the three-year average that it had used for other accounts. Even more serious, claims SDG&E, is the fact the staff did not escalate the average it had obtained to 1983 and 1984 dollars. This resulted in the same additions for 1983 and 1984, a total of $40,798,000 for each year. SDG&E claims that if the staff method of escalation were employed consistently, and the staff conceded this, its estimate would be $50,043,000 for 1983 and $53,310,000 for 1984. However, we note SDG&E's estimates for 1983 and 1984 are $41,972,000 and $37,521,000, which we adopt.

The staff made an adjustment for redefined property units in 1983 of minus $1,203,000 and in 1984 of minus $1,380,000. SDG&E, in making its capital projects submissions with the rate case, adjusted plant additions by $517,000 for 1983 and $559,000 for 1984. SDG&E claims staff should take that into account. However, staff made its own independent estimates which are unrelated to SDG&E adjustments and which we find appropriate and will adopt.

13.2 SONGS Common Plant

Staff removed two-thirds of SONGS common plant for consideration in SDG&E's A.82-03-63. A.82-03-63 is an offset proceeding brought by SDG&E to consider the revenue effects of the start up of SONGS ~~Units 2 and 3. Staff believes the offset~~ proceeding is the proper place to determine the reasonableness of the costs for those facilities, part of which is the cost of facilities. Also, staff, when it presented its recommendation, believed that SDG&E was considering the sale of a portion of its 20% share in SONGS Units 2 and 3. However, under cross-examination, the staff witness conceded that that was no longer a possibility. The effect of the staff recommendation is to reduce 1983 BOY plant by $3,067,000, 1983 plant additions by $5,429,000 and 1984 additions by $4,947,000. The effect on 1984 weighted average electric plant is a reduction in rate base of $9,535,000. The company claims that the cumulative effect of removing the pre-1983 and 1984 additions on the 1984 test year rate base is $10,055,000.

The staff witness agreed that $3,067,000 of the SONGS common facilities adjustment had closed to plant by the end of 1981 and was authorized for capitalization in SDG&E's 1982 general rate case. He further acknowledged that FERC instructions direct that expenditures common to a project as a whole shall be included in electric plant-in-service upon completion of the first unit.

We will not accept the staff adjustment. Normal accounting procedures would allow capitalization of common facilities of a plant that is being phased in such as SONGS. Further, if the staff wishes to make an adjustment for revenue requirement purposes they can make an appropriate proposal in A.82-03-63 including the effect of the actions we take by this decision.

13.3 SONGS Sleeving Capitalization

As discussed in Section 6.4 we have expensed the SONGS sleeving costs. Accordingly, we will make appropriate rate base adjustments as recommended by the staff.

13.4 Distribution Facilities Information System (DFIS)

The staff incorporated the capital savings accruing from the implementation of DFIS. We will accept that estimate but tempered by the adjustments to the DFIS expenses which resulted in some DFIS costs being included in the electric department and excluded from the gas department for this rate case.

13.5 Property Held for Future Use (PHFU)

This portion of the discussion of PHFU for rate base purposes excludes the matter of the Blythe Site which we will discuss later.

A staff witness submitted a proposal for PHFU guidelines to be used for rate purposes. He indicated they were not to be applied to SDG&E in this proceeding but that they should be considered in the 1986 test year proceeding. We accept that recommendation.

The staff made several adjustments to electric plant property held for future use. These adjustments were made because, in staff's opinion, SDG&E had no imminent plans for the use of certain parcels of land. The company stipulated to the adjustments made in staff's Exhibit 25. Staff claims in its brief that through inadvertence, it omitted the exclusion of the Valley Center Substation parcel which is not intended to be used by the company until the year 2000. The staff has modified its showing to make that exclusion and in the absence of any objection by SDG&E, we assume it stipulates to that exclusion; it amounts to an additional $54,000 disallowance.

The only other issue between the staff and the company on property held for future use is related to an electric generator turbine shell for the company's Silver Gate Power Plant. The shell presently in operation showed a crack in 1970 and a new shell was ordered and received in 1974 but has not been installed to date. The company expects it may install the replacement in 1986. Staff questions whether or not SDG&E ever intends to put the shell in place considering the amount of time that has passed while the apparently defective turbine shell has been serving without incident. Staff notes that current company plans show Silver Gate to be relegated to wet storage, that is, nonuse, in 1984; staff submits that the company has failed to prove the reasonableness of its plan for use of the turbine shell. We agree with staff and will exclude the shell from PHFU.

The City of San Diego and the Welfare Rights Organization argue for much more stringent treatment of property held for future use and recommend that a total of $841,900 in properties listed in PHFU be excluded from rate base in this proceeding. These include certain properties recommended for elimination by the staff and stipulated to by SDG&E. We must agree that properties that have an expected utilization date of 1995 and beyond for instance, and some that don't have any expected in-service date at all, should be carefully screened for reasonableness before they are continued in property held for future use. See Table 4. They of course affect the return expected of ratepayers and the concomitant revenue requirement for the support of such properties. We note again that the staff has made a proposal concerning guidelines for PHFU to be considered in the company's 1986 rate case. We admonish our staff to take a very close look at PHFU and those guidelines preparatory to their presentation in the 1986 rate case. Property that appears to have no use in the company plans for the future or which appears to be speculative in nature, as pointed out by San Diego and WRO, should be excluded from rate base.

TABLE 4

Item	When Acquired	Utilization Date	Value
Ash Street Substation	1977	1989	$106,900
Central Valley Substation	1974	1992	37,000
Laurel Substation	1975	1995	304,900
North San Clemente Substation	1972	1995	37,300
Ramona Substation	1966	1990	80,900
San Diguito Substation	1968	1995	20,400
Valley Center Substation	1974	2000	53,800
North San Clemente R/W	1976	1995	160,500
Carlton Hills South Bay R/W	1976	Unknown	40,200
	1973	Unknown	4,500
TOTAL			$846,400

13.6 Free Footage Allowance

The Commission has before it Case (C.) 10260 concerning extension rule adjustments. The staff attempted to anticipate the effects of the Commission resolution of the extension rule issue in its estimates of rate base. However, the staff witness acknowledged that final resolution of the extension rule issue is uncertain because of pending legislative action on Senate Bill 48 which could result in delaying a Commission decision in C.10260. At the request of the company, the staff filed Exhibit 126 which revises the gas and electric results of operations tables to reflect the existing free footage allowances for line extensions. On September 27, 1983, the Commission issued D.83-09-066 which set new hearings on the matter and rejected SDG&E's tariff filing which would have eliminated free footage allowances. Accordingly, we will not attempt to anticipate the effects of any changes in the extension rule; we reject the staff proposal as it now affects the main extension rule.

13.7 <u>Materials and Supplies</u>

Based on our D.82-12-045 in Continental Telephone's A.82-01-01 dated December 8, 1982, staff recommended that a large part of the company estimate for materials and supplies be excluded from rate base. The reason for this exclusion is that the majority of SDG&E's materials and supplies are eventually charged to capital projects.

Normally, when SDG&E starts a capital project, it purchases materials for use on that project and books them to construction work in progress (CWIP). There they accrue AFUDC interest until the completion of the project and its capitalization into utility service. Pending a project's completion CWIP is not included in rate base. Staff claims that SDG&E draws upon its materials and supplies account rather than original inventory to supply many projects, in effect receiving rate base treatment for CWIP prior to the completion of construction. The staff's proposal would require SDG&E to record 78% of its materials and supplies in a sub-account accruing AFUDC. Staff maintains this would provide for identical treatment of both materials and supplies charged to capital projects and those booked to CWIP.

Staff conceded that additional bookkeeping associated with AFUDC accruals may be required but did not believe it would be an unreasonable burden on SDG&E to set it up.

During the course of the hearing, the staff took some conflicting positions on this matter. There was an attempt at a revision of its SDG&E position because in the concurrent PG&E rate case staff did not make a similar proposal to that for SDG&E. Staff counsel explained that in the PG&E case, the staff electric operations witness originally proposed a 20% disallowance of materials and supplies while the staff gas operations witness proposed inclusion of all materials and supplies in rate base. Staff counsel indicated the staff electric witness in the PG&E case withdrew the exclusion proposal and recommended all materials and supplies be included in rate base for PG&E.

We believe the staff proposal in this matter has not been thoroughly thought through. The implications for CWIP and AFUDC and their effects on revenue requirement which might offset the exclusion have not been fully considered. We have reviewed the Continental Telephone D.82-12-045 and conclude that the conditions in that case may not be the same as for SDG&E, particularly concerning an allowance for CWIP. We will not accept the staff proposal in this proceeding because, as we said in the Continental decision,

> "Exclusion from rate base of inventory destined for use in construction is consistent with this Commission's general policy rejecting rate base treatment of nonoperative CWIP. On the other hand, it is inconsistent for staff to recognize the reasonableness of Continental's inventory levels while seeking to deny any recovery of the associated carrying costs. It would be appropriate to permit Continental to establish a new account for M&S construction inventory to accrue interest at the same rate as a CWIP account. Such accrued interest ultimately will be eligible for inclusion in rate base on the same terms as interest in CWIP accounts. To recognize the probable lag between acquisition of inventory and payment therefore by Continental, interest on construction inventory should accrue only from the date of payment for inventory items, subject to reasonable averaging for purposes of accounting convenience." (Mimeo. p. 19a.)

13.8 Working Cash Allowance

Some of the differences in estimates for working cash result from differences in estimates of expenses and revenue requirements between SDG&E and the staff. These working cash differences will be resolved in a manner consistent with the resolutions we make on expense and revenue estimates.

There are other differences between the working cash estimates which must be resolved. These fall into three areas, escalation, clearing accounts, and miscellaneous debits.

For Accounts 143 and 183, the staff used a nonlabor escalation factor, whereas, these accounts contain both labor and nonlabor. SDG&E used the CPI to escalate these accounts which it considers to be proper. The company's method is more appropriate and its estimates will be adopted.

Staff recommends disallowance of certain clearing account balances included in working cash allowance by SDG&E. These accounts represent expenses which are associated with certain operations of the company not yet cleared to specific expense accounts. There is always an amount carried for these uncleared balances. The company estimates its clearing account expenses by weighting each month's uncleared balance and escalating using the CPI. SDG&E claims that the Commission's Standard Practice U-16 clearly states that the uncleared amount should be included in rate base because they represent a continuous amount carried on the books. This is the manner in which we have treated this in the past for SDG&E and, in particular, in its 1982 rate case. Staff has not convinced us in this proceeding that we should treat it otherwise. We will adopt the company's method.

Staff recommends disallowance of certain miscellaneous debits which are the unauthorized portion of prior expenses. SDG&E claims it included only the types of expenses in the deferred debits accounts which were included in its 1982 general rate case decision. These expenses were not at issue in the 1982 rate case and were included and approved in that case. Commission Standard Practice U-16 includes miscellaneous deferred debits in the rate base. The staff witness acknowledged that this disallowance was based on his personal opinion and he did not know if it had ever been advanced or adopted in any prior rate cases. We will adopt the company's base treatment has been examined several times since, most recently in SDG&E's 1982 rate case. In that case by D.93892 the Commission included the Blythe site in rate base at the 1979 test year authorized rate of return of 10.59 percent. However, we placed SDG&E on notice that it must come up with a specific plan for the site if it is to be included in its 1984 test year rate base. Specifically, the Commission stated:

> "We will permit the retention of the Sundesert site-related costs in plant-held-for-future-use at this time but will limit the rate of return on this to 10.59% which is the return we authorized when the site was first placed in plant-held-for-future-use. We hope that our decision today will serve as an incentive to SDG&E to make some specific plans for the site.
>
> "We will place SDG&E on notice that the Sundesert site will be removed from PHFU in the next general rate case, unless a specific plan exists for proposed use or disposition of the site. The Company's showing should detail its specific plan for use of the site, the need for additional generation capacity, the availability of alternative resources, and the economic benefit if any of retention of the site in PHFU as opposed to sale of the property. Such a showing is consistent with the Commission's intent in Decison 90405 which anticipated generation facility plans for the site as well as review of the rate base inclusion of site related costs in SDG&E's general rate case." (Mimeo p. 159.)

It is clear then that what we expected the company to show was:

1. A detailed specific plan for use of the site;
2. The need for additional generation capacity;
3. The availability of alternative resources; and,
4. The economic benefit, if any, of retention of the site in PHFU as opposed to sale.

position and include miscellaneous deferred debits in the working cash allowance.

13.9 Undistributed Fuel Expense

SDG&E's Fuel-in-Storage estimate exceeds the staff's by $548,000. The difference is due entirely to undistributed fuel handling expense.

SDG&E used a computer simulation model of its electric generation operations to estimate its budget for 1982 and escalated this to forecast its 1984 expense. Staff used actual 1982 expense escalated to 1984. Because staff's method reflects actual conditions it will be adopted.

13.10 The Blythe Site

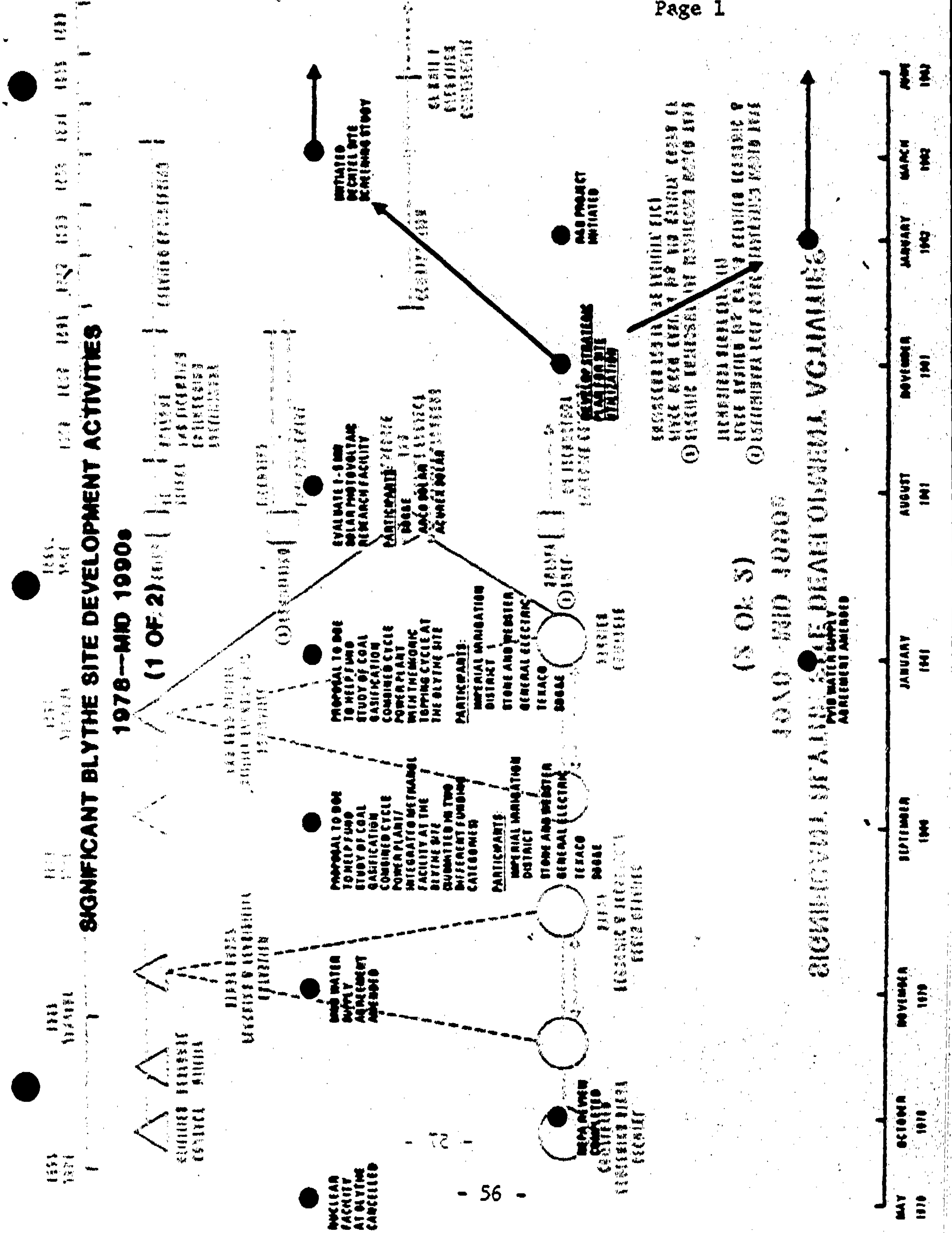
The largest single issue in rate base is inclusion by SDG&E of its so-called Blythe site. The Blythe site is left over from the company's abandoned Sundesrt nuclear project which was cancelled in May, 1978. The site, totally owned by SDG&E, contains approximately 6,500 acres of land and is located 16 miles from Blythe, California, and 6 miles west of the Colorado River. Also, there are water rights at the site. These rights, which are firm and committed for power plant usage, constitute 33,000 acre feet of waste water per year provided by agreements with the Palo Verde Irrigation District and the Metropolitan Water District. When the Sundesert project was cancelled, SDG&E sought to recover the abandoned plant costs in its 1979 test year general rate case, A.58067. By D.90405 dated June 5, 1979, the Commission found in Finding 11 that:

> "SDG&E's management was not imprudent in its inception, continuation, and termination of Sundesert considering the circumstances that existed at the time SDG&E had to make its decision." (Mimeo. p. 94.)

The Commission authorized a five-year amortization of $37.2 million of non-site related costs and the inclusion of $45 million of the site-related costs in property held for future use. This rate

13.10.1 SDG&E's Specific Plan for Use of the Blythe Site

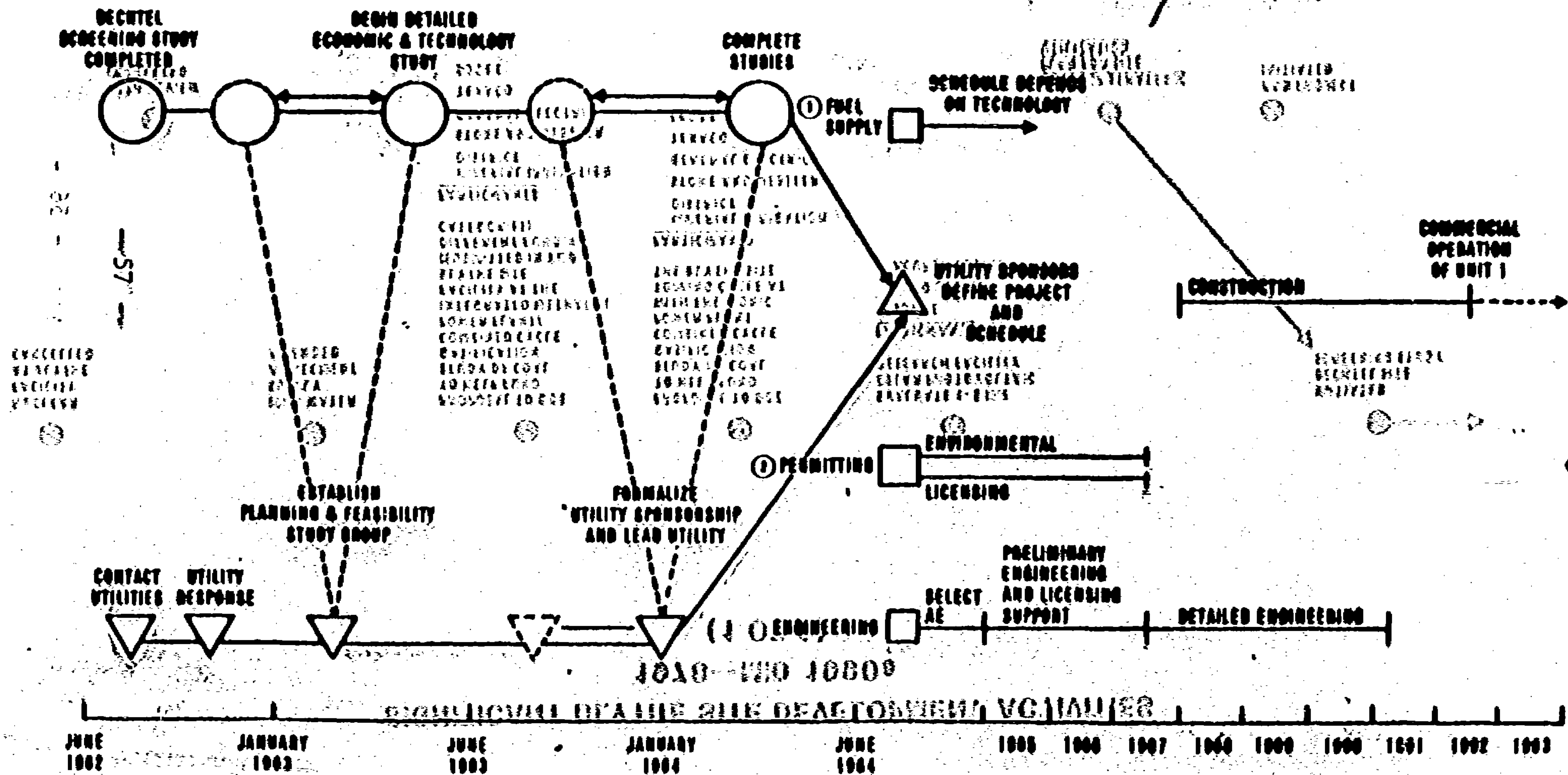
SDG&E expects the Blythe site to be developed by a consortium of California and southwestern utilities. SDG&E's plans are to contribute the site, the pertinent water rights, and its status of licensing certainty to the consortium in exchange for about a 25% ownership interest in the generating capacity which at its peak is expected to be up to 2,500 megawatts. SDG&E has filed its 1983 GO-131-B resource plan with the Commission in which it contemplates operation of the first generating unit at Blythe between 1992 and 1995. Chart A from Exhibit 18, witness Anastas, shows the significant Blythe site development activities past and planned by SDG&E. At present, SDG&E is trying to identify the most appropriate generation technology and the specific participants in the consortium. The schedule contemplates the organization of a planning and feasibility study group among potential consortium members in 1983 to assess how best to develop the site. In 1984, financial commitments from participants will be obtained and planning, engineering, and permit activities will commence, including identification of the fuel source for the preferred technology. To achieve the short term aspects of the long range plan, SDG&E is presently meeting with 17 southwestern utilities to investigate levels of interest. As far as capacity is concerned, SDG&E expects that the value of the site will be its contribution and the only contribution required for its approximate 25% interest. It expects to have 625 megawatts of capacity from the site by the year 2000. This 625 megawatt capacity would be staged from 1992 to the year 2000 in five 125-megawatt increments.


SIGNIFICANT BLYTHE SITE DEVELOPMENT ACTIVITIES
1978—MID 1990s
(1 OF 2)

SIGNIFICANT BLYTHE SITE DEVELOPMENT ACTIVITIES
1978—MID 1990s
(2 OF 2)

(1) PRELIMINARY FUEL SOURCE EVALUATION WOULD TAKE PLACE EARLIER (e.g. DURING DETAILED ECONOMIC & TECHNOLOGY STUDY EFFORTS)

(1) SPECIFIC ENVIRONMENTAL MONITORING WOULD TAKE PLACE MUCH EARLIER (e.g. AIR QUALITY, CORPS OF ENGINEERS FOR INTAKE FACILITY, ETC.)



To evaluate the possible technologies that may be used at the site, SDG&E commissioned the Bechtel Corporation to make a site screening study. This study reviewed 20 technologies for their suitability at Blythe. That 20 was narrowed to six which were found to be potentially appropriate and economical for development at the site. These six center around three major technologies, biomass, coal, and solar thermal.

One of the main benefits SDG&E expects out of the Blythe site is the prospect of developing a power plant that may assist in meeting non-California power needs. This would ameliorate what SDG&E sees as a historical reliance of California utilities on non-California resources for electricity. Non-California utilities, claims SDG&E, have shown an increasing reluctance to export energy to California and development of Blythe is very likely to help avoid California's energy isolation in the southwest.

13.10.2 <u>The Need for Additional Generating Capacity</u>

To respond to the Commission's request that the Company show the need for additional generating capacity, SDG&E presented witness T. G. Roemmelt, who is Manager of System Planning for SDG&E. Roemmelt testified that SDG&E is striving to provide the lowest cost options without undue risk of failure of those options in availability, timing and cost of generating capacity. To reduce risk, SDG&E is diversifying its fuel supply as much as possible. It hopes to achieve its ultimate goal of rate stability by reducing its dependence on oil, or any other singular fuel or technology, where an adverse event can significantly increase rates. He testified that Blythe is a resource that is part of a group of resources which collectively reflect company policy of diversification of fuel supply and reduced dependence on oil. In addition to Blythe as a generating resource in the future, the company's resource plan includes cogeneration, hydro, wind, biomass, nuclear, coal purchases from Arizona and New Mexico, purchases from the northwest, geothermal purchases from Mexico, and the Imperial Valley, and SDG&E development of Imperial Valley geothermal. Starting in 1992, with 125 megawatts of power, the Blythe development could provide a total of 625 megawatts for SDG&E by the year 2000. SDG&E estimates that in each even-numbered year during that period, 125 more megawatts would be added from the Blythe resource. For planning purposes SDG&E is considering that generation at the site would be coal-fired. But all that SDG&E really desires is that it be a relatively inexpensive base load capacity. Roemmelt testified that the resource plan with the Blythe development in it reflects an oil/gas dependency of approximately 30% in the 1990s. Without Blythe, that dependency will increase to 40%.

Other advantages which may result from the development of generation at the Blythe site would be the site's contribution to the reliability of energy supply for SDG&E's customers and its contribution to the supply needs in general of the entire southwest region. Roemmelt believes that without the Blythe site development there would be no reserves or contingencies by the year 2000. He belives this is totally unacceptable because each contingency could mean an outage for SDG&E's customers. With respect to the regional value of the Blythe site, numerous southwest utilities anticipate need for capacity between 1992 and 2000. Utilities showing a need for base load capacity in their resource plans for the 90's according to Roemmelt are Southern California Edison, Arizona Public Service, Pacific Gas & Electric, Public Service Company of New Mexico, Imperial Irrigation District, Los Angeles Department of Water and Power, and Arizona Electric Power Cooperative. None of these utilities has an approved site for a base load capacity similar to the Blythe site. Roemmelt testified that Blythe is an approved power plant site with a water supply for up to 2,500 megawatts and therefore, could serve the entire southwestern region including SDG&E customers.

Witness Roemmelt offered Table 5 which lists the base load power plants planned in the Southwestern United States during the 1990s. To the right of the individual units planned are designated the major utility involved, the planned capacity, location, date on line, water availability, access to rail transportation and transmission facilities. Data for this table were derived from several sources including resource plans submitted to the Southwest Area Transportation Planning Coordination Committee (SWAT), July 15, 1982, as amended September 1, 1982. Contributing utilities included:

Arizona Electric Power Cooperative
Arizona Public Service Company
El Paso Electric Company
Los Angeles Department of Water and Power
Public Service Company of New Mexico
Salt River Project
San Diego Gas & Electric Company
Southern California Edison Company
Tucson Electric Power Company
Western Area Power Administration

Roemmelt testified that most of the sites shown on Table 5 are in the early planning stages including siting, environmental, air quality, and land usage analysis. He claims that much of this work has already been completed on the Blythe site. He also stated that compared to the Blythe site, many of these projects do not have firm water supplies.

TABLE 5

SOUTHWEST BASE-LOAD PLANT STARTUPS (1990'S)

UNIT NAME	UTILITY	CAPACITY (MW)	LOCATION	DATE ON LINE	WATER	RAILROAD	TRANSMISSION
NMS 1,2, 3,4	PNM	2000 (500 EA)	NW New Mexico; 35 mi. South of Farmington	1990,1993 1995,1998	Source not firm	Mine mouth plant - also, Santa Fe building spurline	Three 500 KV lines 1985 and 1982
Harry Allen 1 & 2	NPC	1000 (500 EA)	25 mi. North of Las Vegas	1989,1990	Wastewater effluent	Existing - Coal supply is slurry pipeline	2-500 KV lines to El Dorado Planned
White Pine 1 & 2	NPC	1500 (750 EA)	Site not selected but in White Pine County, NV	1995,1996	Unknown	Existing for copper mines	345 or 500 KV lines planned
Cholla 5	APS	340	East of Flagstaff	1991	Groundwater	Existing	No additional necessary
Bouse 1, 2,3	APS	1050 (350 EA)	West of Palo Verde	1993,1995 1997	Unknown	1/2 mi. from existing rail	Close to Palo Verde-Devers 500 KV
AEPCO 1 and 2	AEPCO	550 (275 EA)	Siting study in progress	1990,1994	Unknown	Unknown	Unknown
Springer-ville 3	TEP	350	Arizona-New Mexico Border	1991	Groundwater	Existing	(?) 345 KV lines 1982-1987
Coronado III	SRP	350	22 mi. NW of Springer-ville	1991	Groundwater	Existing	Adequate transmission for two more units
Future Coal	SRP	500	Siting study in progress	1995	Unknown	Unknown	Unknown
Totals:	Projects 9 Units 17 Megawatts 7640						

NOTE: Pacific Gas & Electric Company identifies no specific base-load units in the 1990's, but does show 5000 MW of Generic Base (800 MW in 1997, 1998, and 2000, and 900 MW in 2001 and 2002.)

Chart B lists the cumulative base load capacity additions for the southwest as derived from Table 5. As can be noted, there are nine projects consisting of 17 units totalling 7,640 MW by the year 2000. Roemmelt claims this is an excellent demonstration of the southwest need for power plant sites including Blythe.

We note that Chart B may be somewhat misleading in that it assumes that the Blythe site would provide generating capacity as early as 1989, whereas the record is clear that the first units will probably come on line no earlier than 1992. Further, they will be staged between 1992 and the year 2000; therefore the indication that there are 2,000 megawatts available from Blythe as early as 1991 is misleading. On the other hand, the record is clear that many of the projects which are shown on Table 5, and which form the basis for the capacities indicated Chart B, are far from certain of construction and, in fact, some have already run into troubles.

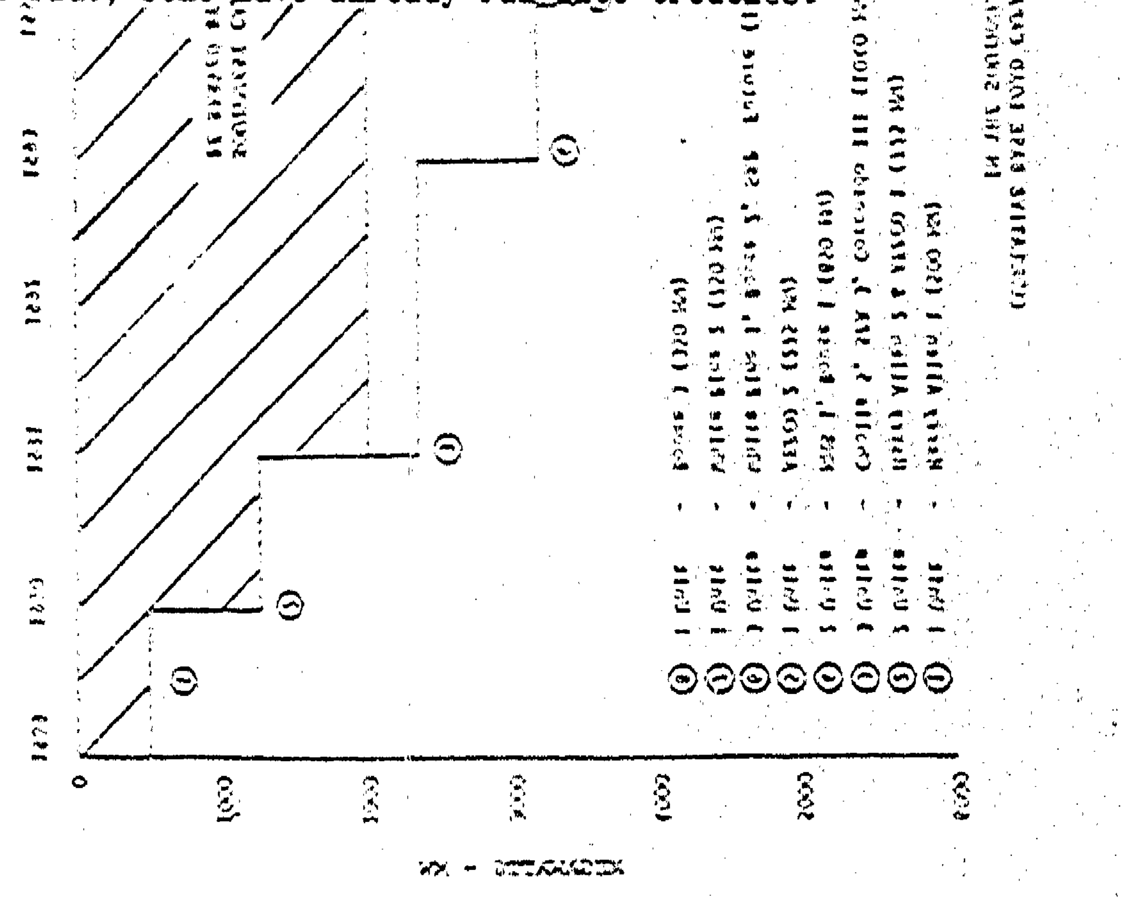
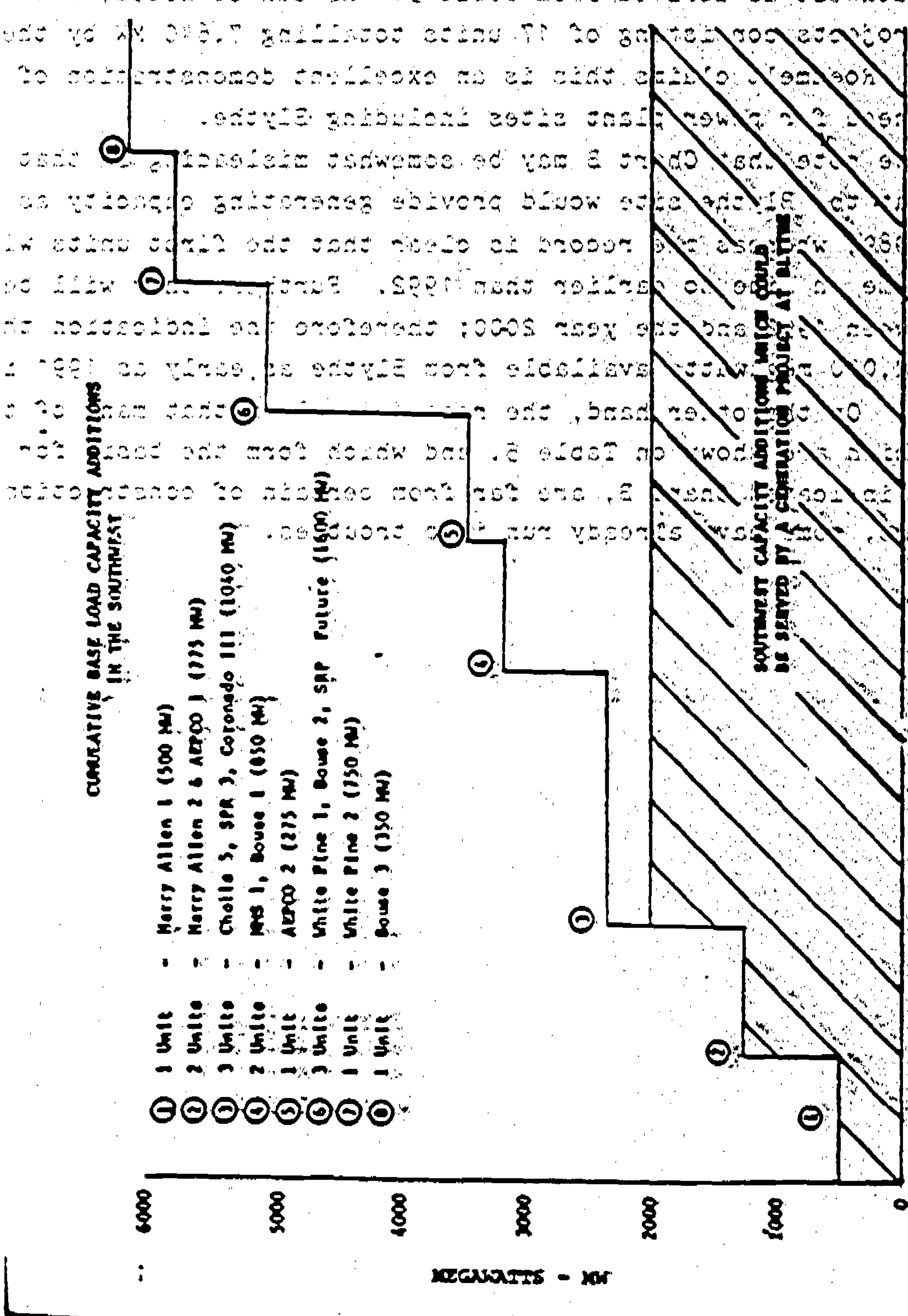


Chart B


CUMULATIVE BASE LOAD CAPACITY ADDITIONS IN THE SOUTHWEST
① 1 Unit - Harry Allen 1 (500 MW)
② 2 Units - Harry Allen 2 & AEPCO 1 (775 MW)
③ 3 Units - Cholla 5, SPR 3, Coronado III (1040 MW)
④ 2 Units - NHS 1, Bouse 1 (850 MW)
⑤ 1 Unit - AEPCO 2 (275 MW)
⑥ 3 Units - White Pine 1, Bouse 2, SRP Future (1600 MW)
⑦ 1 Unit - White Pine 2 (750 MW)
⑧ 1 Unit - Bouse 3 (350 MW)
SOUTHWEST CAPACITY ADDITIONS WHICH COULD BE SERVED BY A GENERATION PROJECT AT BLYTHE
MEGAWATTS - MW
0
1000
2000
3000
4000
5000
6000
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998

13.10.3 The Availability of Alternative Resources

Witness Roemmelt stated that SDG&E had examined several alternatives to the Blythe site including conventional oil and natural gas, combustion turbines, repowering of existing units, conventional hydroelectric power, goethermal, the purchase of off-system energy, and participation in power plant projects of other developers. He claimed the examination of each of these alternatives had confirmed the need to preserve and develop the Blythe site.

SDG&E presently generates most of its base load energy from on-system conventional oil and gas-fired power plants. Because of the decline of domestic production and the increase in demand for oil and natural gas, there has been a greater reliance on imported oil. And competition has increased for natural gas and for the limited supplies of low sulphur fuel oil which are required if electric utilities are to meet local air quality regulations. Of course, since the oil embargo in 1973, the cost of fuel oil has increased phenomenally. Although the technology is proven and reliable, construction of additional conventional oil-fired generating units would increase SDG&E's dependence on expensive imported oil and increase the risk of another embargo. Roemmelt believes it is contrary also to national energy policy because conventional oil and gas-fired units are effectively precluded due to restrictions in the Power Plant and Industrial Fuel Use Act of 1978 (FUA). FUA prohibits the use of natural gas or petroleum as a primary energy source in any new electric power plant as defined by FUA. FUA provides that no new electric power plant may be constructed without the capability of using coal or other alternative fuels. Although FUA has provisions for exemptions, as a practical matter such exemptions are not reasonably available. Therefore, construction of any new oil- or gas-fired generating facilities in Southern California appears remote. Therefore, SDG&E concludes that new conventional oil and natural gas base-load generation is not a viable alternative source of power.

Roemmelt testified that combustion turbines are commercially available at a relatively low capital cost. However, they use high-cost gas and oil fuels and are therefore used for peaking applications and are not economic for base-load applications. Again the use of fuel oil and natural gas would be contrary to FUA and national energy policy. Therefore, SDG&E considers the installation of combustion turbines is not considered a reasonable alternative source of power.

Another possibility is repowering existing plants. This involves making substantial changes in existing older power plants to increase their capacity and improve efficiency. However, the major drawback to repowering is that current technology requires the input fuel be either natural gas or fuel oil. The repowered facilities would be treated as new facilities with respect to present air quality regulations and therefore SDG&E does not consider repowering to be a viable alternative source of power.

Roemmelt testified that sites for installation of conventional base-load hydroelectric generating facilities are severely lacking in Southern California. Any installations of this nature would be very small and therefore conventional hydroelectric utilities are also not considered a viable alternative source of power. Pump and storage hydroelectric facilities could feasibly provide additional peaking capacity but they are generally not considered a reasonable alternative source of power for base load purposes.

Geothermal is a possibility and SDG&E's plans include several potential geothermal resources in the Imperial Valley. Before this potential can be realized though, more development work is needed including the construction of commercial-size demonstration units. SDG&E has signed a contract to purchase power from a nominal 24-megawatt geothermal plant to be built by Magma Power Company at Nyland. SDG&E has also signed a letter of intent with Magma for a 50-

megawatt plant. The target dates for operation are '83-'84 for the 24-megawatt and '85-'86 for the 50-megawatt plant. In addition, SDG&E is participating with three other utilities, EPRI, and the Department of Energy in developing a 50-megawatt binary geothermal plant at Heber. It is expected this plant may come on line in 1986 at the earliest.

Geothermal energy is included as an element of SDG&E's resource plan since current activities in development and demonstration of Imperial Valley geothermal resources are expected to prove the economics and reliability of this resource by the late 1980's. However, SDG&E does not believe geothermal technology is a reasonable alternative in the time span parallel to its proposed development of the Blythe site.

Another alternative SDG&E considered was purchased power contracts. Although opportunities exist for SDG&E to make purchases of power throughout the '90's from other utilities, they are not considered a good alternative to development of the Blythe site. This is because there are few opportunities to purchase large blocks of reliable base-load capacity for the 30 to 40 years that development of the Blythe site would serve its customers.

The last alternative considered by SDG&E was participation in power plant projects of other developers. Such projects are being planned for the '90's by utilities in the southwest. However, most of these projects have only tentative sites, but they could be relocated at the Blythe site in which case SDG&E would be a joint participant. SDG&E claims that this concept underlies the company's plan for the Blythe site development.

13.10.4 <u>Economic Benefits of Retaining the Blythe Site in Rate Base</u>

SDG&E had two separate appraisals made of the site for two different purposes. First, it engaged the firm of Bookman-Edmonston to determine the value of the mesa lands and farmlands for uses other than as a power plant location. That appraisal was set at $30 million. Second, SDG&E had the site appraised as a future power plant location by Woodward-Clyde Consultants, a power plant siting concern. As a future power plant location, Woodward-Clyde put its value in excess of $200 million in 1982 dollars and $435 million in 1992 dollars.

The company presented witness K. T. Mao, a vice president of Woodward Clyde Consultants, who made the estimate of the value of the Blythe site as a power plant location. Mao testified that such use of the site constitutes the best and highest use of the site's resources in meeting regional energy environmental land use and economical needs of California in the southwest. He concludes that the cost of a replacement site and, therefore, the value of the Blythe site as a power plant location, would be about $200 million dollars in 1982 dollars. Mao testified that he considered three traditional approaches to determining the value of the property: the market approach, the income approach, and the replacement cost approach. He dismissed the first two approaches as either not applicable or not easily applied to the Blythe site. There are no recent sales of power plant sites nor are these types of sites income generators in a traditional sense. He believes the only reasonable approach is to apply the replacement cost concept of valuation.

By that method he develops an estimate for the cost of finding and developing another site that has water, land and the licensing-certainty attributes equivalent to Blythe. Mao claims that even using the replacement cost approach, the appraisal is a difficult one to undertake. He believes the analysis clearly cannot be a deterministic one in view of the many uncertainties. The approach he used in his study assesses the replacement value on a probability basis. The actual Blythe site related costs as well as the licensing experience with other power plant projects in California, the southwest, and elsewhere were used as a basis of judgment in estimating the replacement cost. In making his estimate, Mao assumed that the present $45 million that is in rate base was all spent in the year 1977. Twenty million dollars was spend to acquire the water rights and the land, and twenty-five million dollars was spent in licensing related studies and efforts. A key assumption in his estimating procedure was that the first increment of new capacity provided by the site would be needed in 1995. Mao converted his 1977 dollars to 1982 dollars on the historical and projected Producers Price Index (PPI). He used a discount rate of 9% for the cost of money. Mao believes the PPI which he used instead of the Consumer Price Index, more closely approximates utility situations where capital expenditures are involved. He estimated his cost of replacement based on the two major components of the site, licensing and water and land. Based on judgment regarding the licensing cost and the water and land cost, inflation rates using the producers price index, and a discount rate of 9%, Mao estimates that the replacement cost of the site in 1982 dollars would be $206 million. About one-third would be licensing costs and about two-thirds would be land and water. The $206 million estimate was arrived at from estimates that the cost of a replacement site would range from about $175 to $222 million in 1982 dollars. In summary, his judgment is that a value of $200 million in 1982 dollars for Blythe as a power plant site is reasonable.

SDG&E presented Jeffrey J. Straman, who is an engineering economist for SDG&E. Straman sponsored a study summarizing the company's economic analysis of the Blythe site. Straman concluded that it would be more advantageous to SDG&E's customer to preserve the site in rate base until capacity is required than it would be to sell the site now and enter into a new investment in the future to satisfy capacity requirements. As a starting point, Straman used Mao's estimate of $200 million as a power plant site value for Blythe in 1982 dollars and a market value, if the site were sold as agricultural land, of $31.5 million based on the Bookman-Edmonston study. Straman concluded that the results of his analysis indicate that SDG&E's customers would receive approximately a 2 to 1 benefit for continuing to carry the Blythe site in rate base. The value of capacity represented by the customers carrying these costs is on the order of $400 to $600 million depending on the date of operation of the first unit. This analysis considered three in-service dates: 1992, 1995, and 1998. Straman concluded that if the existing site were sold, a cash payment of approximately $150 to $300 million at the time of operation of a new facility would result in the same level of revenue requirement compared to retaining the site in rate base. Therefore, from a revenue requirement perspective, customers would be indifferent between the options of retaining the site or purchasing $150 to $300 million of capacity. From a capacity point of view however, the customer would receive approximately twice as much capacity if the site were retained for a future exchange. He concludes it would be more advantageous to the customer to keep the site in rate base.

At the request of the ALJ, Straman prepared Exhibit 20 which is reproduced here as Chart C. Chart C shows three alternatives. First, retain the site in PHFU. Under this scheme, the amount required to produce 145 megawatts capacity for SDG&E from 1992 until 2021, is $76 million. Second, assume disposal of the site and purchase of capacity at a megawatt level equal to Alternative 1. The present value required to support that alternative would be $247 million. Alternative 3 assumes disposal of the site and purchase of capacity at a rate impact equal to Alternative 1; that is a present cost to ratepayers of $76 million. The capacity which could be purchased for the $76 million at present value is 44 megawatts for the years 1992 through 2021. Summarizing the advantage to ratepayers of retaining the site in property held for future use shows that Alternative 1 has an advantage of about 3 to 1 over Alternatives 2.

and 3. Comparing Alternative 2 to Alternative 1, it would take three times the dollars at present value to purchase a capacity of 145 megawatts in the future if the site is sold. Likewise, if one takes the present dollars available as shown in Alternative 1 of $76 million, the capacity which could be purchased for that sum is 44 megawatts. That is one-third of the capacity if the site were held in PHFU, again, a 3 to 1 advantage. Sheet 2 of Chart C is the second page of Exhibit 20 offered by Straman. The interest rate used in the calculation he made is 10.59 percent which is currently the rate of return authorized by the 1982 general rate case decision on the Blythe rate base. He used a net-to-gross multiplier for the revenue requirement of about 2.1. As an example, the 10.8 million dollars per year calculated on Sheet 1 of Chart C results from multiplying the $47 million rate base times 10.59 percent times a net to gross multiplier of about 2.1.

Straman, in Exhibit 18, offered Chart D to show the value of alternatives for 1992, 1995, and 1998 in-service dates.

One of the keys to an economic analysis of the site is the assumption by SDG&E that it will be able to trade the escalated dollar value of the site in 1992, or later, for its share of any power plant facility built on the site. As an example, SDG&E would have a value of $435 million in the site to contribute to the consortium.

Blythe Site Revenue Requirements
($ Millions)

1. **Retain Site in PHPU**

$45 - PHPU $47 - Rate Base

|84| |92| |2021|

<---- $9.7/yr ----><---------------- $10.8/yr ---------------->

Capacity Value: 145MW

Present Value (PV): $76

2. **Dispose of Site and Purchase Capacity Ownership at MW Level Equal to Alternative 1**

$435 - Capital Investment

|84|85|86|87| |92| |2021|

<- $3.4/yr -><- 0 -><---------------- $87/yr ---------------->

Capacity Value: 145 MW

Present Value (PV): $247

3. **Dispose of Site and Purchase Capacity Ownership at Rate Impact Equal to Alternative 1**

$131 - Capital Investment

|84|85|86|87| |92| |2021|

<- $3.4/yr -><- 0 -><---------------- $24.2/yr ---------------->

Capacity Value: 44 MW

Present Value (PV): $76

SUMMARY: Advantage to ratepayers of retaining site in PHPU

a) PV advantage (Items 1 & 2 above) = $247 : $76 = 3:1
b) MW advantage (Items 1 & 3 above) = 145 MW: 44 MW = 3:1

1. **Retain Site in PHFU**

The time-line shows the average annual revenue requirements to be $9.7m²/yr until the assumed in-service date of 1992. Thereafter, the average annual revenue requirement would be $10.8M²/yr for the 30-year life of the generating facility. The present value of the total revenue requirement is $76M². This alternative purchases capacity value for the ratepayers of 145 MW assuming the value of the site for a generating facility is $435M² and the total per kilowatt cost of capacity in 1992 $ is $3,000/kw. This alternative corresponds to Alternative 1 in Exhibit 18, Chapter 5.

2. **Dispose of Site and Purchase Capacity Ownership at MW Level Equal to Alternative 1**

This time-line shows the effect on revenue requirements of selling the site and purchasing future capacity by means of a shareholder capital investment. Sale of the site is assumed to be at less than book value, resulting in a loss to be amortized over four years. The average annual revenue requirement to cover the loss would be approximately $3.4M² for four years. Future capacity needs of 145 MW (equal to the amount resulting from trading the site for capacity ownership in Alternative 1) would be met by making a shareholder capital investment of $435M² at assumed in-service date of 1992. The average annual revenue requirements for the 30-year life of the plant would be $87M². The present value of total revenue requirements is $247M². This alternative results in 145 MW of capacity but requires an additional $76M²/yr from the ratepayers over the 30-year life of the plant. This alternative corresponds to the response to ALJ Porter's question at transcript page 1445.

3. **Dispose of Site and Purchase Capacity Ownership at Rate Impact Equal to Alternative 1**

This time-line shows the effect of disposal of the site and purchase of future capacity by making a shareholder capital investment which would have the same rate impact as Alternative 1 above. Loss on sale of the site would result in average annual revenue requirements of $3.4M² for four years. A future investment of $131M² would result in an average annual revenue requirement of $24.2M² for the 30-year life of the facility. The present value of the total revenue requirement is $76M², identical to that for Alternative 1. However, this alternative results in only 44 MW of capacity based on the $131M² investment and the total per kilowatt cost of capacity of $3,000. This alternative corresponds to Alternative 2 in Exhibit 18, Chapter 5.

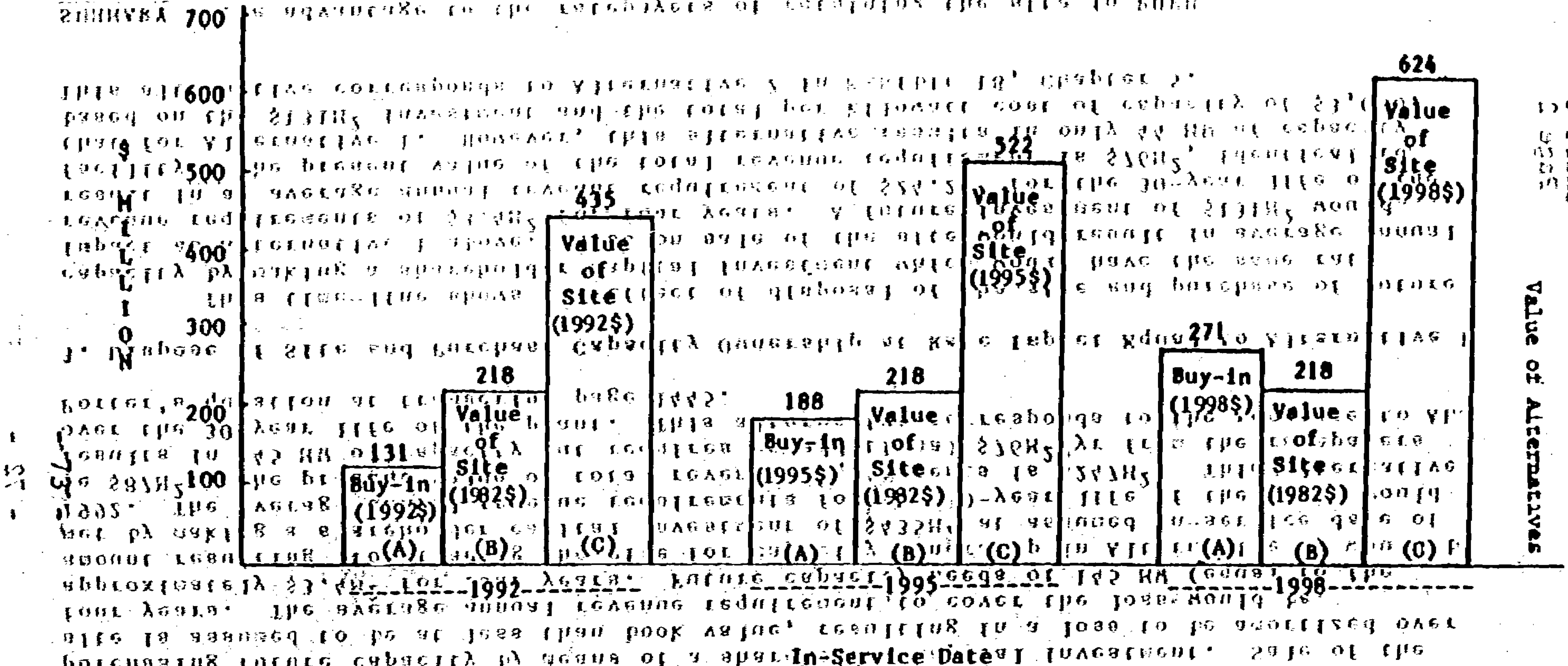
SUMMARY The advantage to the ratepayers of retaining the site in PHFU has been shown to be:

a) PV advantage (Items 1 & 2 above) = $247 M² : $76 M² = 3:1
b) MW advantage (Items 1 & 3 above) = 145 MW : 44 MW = 3:1

A.82-12-57 /ALJ/bg

Chart D

Value of Alternatives



Notes:

(A) Buy-in/purchase price of capacity at in-service date (shown in 1992, 1995 and 1998 dollars) which would produce same cost to customer as retaining site in rate base. (Assumes recovery of difference between book value of site and its sale price in rates.)

(B) Estimated replacement cost of existing site - per Woodward/Clyde Study.

(C) Estimated replacement cost of existing site escalated to 1992, 1995 and 1998 dollars with Producer Price Index (PPI) per Woodward/Clyde Study.

That estimate, SDG&E claims, would provide it with 145 megawatts of capacity in 1992. This would be approximately equal to what it expects to need in 1992. 125 megawatts is what SDG&E expects out of the plant in each of the even numbered years 1992 to the year 2000, 125 megawatts for each two-year period for a total of 625 megawatts.

Straman assumed a capacity value of $3,000 per kilowatt in 1992 dollars to calculate the 145 megawatts from the $435 million in 1992 dollars.

During the hearing there was a great deal of discussion concerning the historical cost of Blythe to SDG&E's ratepayers and shareholders. In response to another request of the ALJ, SDG&E prepared and submitted Exhibit 19. See Table 6. Table 6 compares the historical costs which have been borne by the shareholders to those borne by the ratepayers for the Blythe site. The cost to SDG&E's ratepayers through 1983 has been about $80 million, and the cost to the shareholders about $72 million including the $45 million currently in rate base. SDG&E claims this does not include what it considers to be an insufficient return on the present $45 million investment because that return has been 10.59% in lieu of the 12.92% currently authorized by the Commission's decision in the 1982 rate case.

Table 6
Page 1
BLYTHE SITE
COSTS BORNE BY SDG&E RATEPAYERS

Year - Months	Decision Number	(1) Undepreciated Rate Base	(2) Authorized ROR	(3) Net-to Gross	(4) Portion of Year	(5) Revenue Requirements (1)x(2)x(3)x(4)	(6) Amortization of Non-Site Costs	(7) Other Expense (a)	(8) Rents Received	(9) Total (5)+(6)+(7)+(8)
1977 - 5 mo.	D.87639	16,352,000	9.50	1.65	5/12	1,067,990	---	387,306	(374,063)	1,081,233
1978 - 3 mo.	D.87639	16,352,000	9.50	1.65	3/12	640,794				
1978 - 9 mo.	D.88697	17,770,748	9.67	1.66	9/12	2,139,447				
Subtotal 1978						2,780,241	---	349,175	(429,005)	2,700,411
1979 - 1 mo.	D.88697	17,770,748	9.67	1.66	1/12	237,716				
1979 - 4 mo.	D.89857	17,770,748	9.95	1.66	4/12	978,398				
1979 - 7 mo.	D.90405	45,340,000	10.59	1.65	7/12	4,621,450				
Subtotal 1979						5,837,564	5,371,288	273,062	(410,230)	11,071,684
1980 - 12 mo.	D.90405	45,340,000	10.59	1.65	12/12	7,922,485	7,839,996	315,284	(430,230)	15,647,535
1981 - 12 mo.	D.92557	45,340,000	11.36	1.58	12/12	8,137,986	8,114,544	384,491	(458,231)	16,178,790
1982 - 12 mo.	D.93892	45,034,588	10.59	1.66	12/12	7,916,810	8,860,914	359,403	(458,230)	16,678,897
1983 - 12 mo.	D.93892	45,034,588	10.59	1.66	12/12	7,916,810	8,860,914	406,127	(516,840)	16,667,011
Subtotal 1977 - 1983						41,579,886	39,047,656	2,474,848	(3,076,829)	80,025,561
1984 - 12 mo.	D.93892	45,034,588	10.59	1.66	12/12	7,916,810	---	441,312	(516,840)	7,841,282 (b)
TOTAL 1977 - 1984						49,496,696	39,047,656	2,916,160	(3,593,669)	87,866,843

(a) Includes property taxes, depreciation and other.

(b) 1984 revenue requirements are provided at the request of ALJ Porter. The remainder of this table is retrospective.

Table 6
Page 2
BLYTHE SITE
COSTS BORNE BY SDG&E SHAREHOLDERS

	1975	1976	1977	1978	1979	1980	1981	1982	1983	Subtotal 75 - 83	1984	Total 75 - 84
Return on unamortized balance of non-site costs lost by shareholders					3,479,401	3,158,897	2,478,235	1,717,245	587,036	11,420,814	—	11,420,814
Return deficiency on PHFU (10.59% vs. authorized) lost by shareholders								1,049,306	1,197,920	2,247,226	1,197,920	3,445,146
AFDC on non-site costs (which was disallowed in D.90405, 6/5/79) lost by shareholders					3,115,811			—		3,115,811	—	3,115,811
Legal & lobbying costs disallowed in D.90405 (includes $200,000 charged below the line by SDG&E) and lost by shareholders				336,543	868,917					1,205,460		1,205,460
Return on site AFDC ($2.4M disallowed in D.90405) lost by shareholders					145,319	249,118	267,231	303,929	311,691	1,277,288	311,691	1,588,979
Return on land before recognized in a rate proceeding and lost by shareholders	1,041	840,989	969,746							1,811,776		1,811,776
Return on land resulting from actual cost being in excess of value recognized in rates lost by shareholders			52,812	54,826	31,958					139,596		139,596
AFDC not accumulated on site costs after project cancellation (5/78-5/79) and lost by shareholders				1,050,080	980,182					2,030,262		2,030,262
AFDC not accumulated on non-site costs after project cancellation (5/78-1/79--10 yr amortization begun 1/79) and lost by shareholders				1,529,439	277,839					1,807,278		1,807,278
Subtotal	1,041	840,989	1,022,558	2,970,888	8,899,427	3,408,015	2,745,466	3,070,480	2,096,647	25,055,511	1,509,611	26,565,122
Capital committed by shareholders for generating facilities (current PHFU value)							—	—	45,034,588	45,034,588		45,034,588
Site AFDC disallowed							—	—	2,352,388	2,352,388		2,352,388
TOTAL	1,041	840,989	1,022,558	2,970,888	8,899,427	3,408,015	2,745,466	3,070,480	49,483,623	72,442,487	1,509,611	73,952,098

13.10.5 Staff's Position on the Blythe Site

Staff recommends the deletion of the Blythe site from rate base. It claims that SDG&E does not have a definite plan for use of the site as the Commission requested it should in D.93892. Staff claims the lack of a plan is evidenced by three factors:

1. SDG&E is unable to identify any specific partners for a Blythe project.
2. No technology has been selected.
3. No satisfactory timetable for development has been provided.

The staff believes identification of partners in the project is crucial to development of the site because SDG&E will not be the lead utility for the project. In fact, staff claims, SDG&E wants no responsibility for project development, management, or operation. Given its preference, the company would sell Blythe to a project consortium in exchange for purchased power from a Blythe facility. Staff believes that without a consortium Blythe is a nonproject.

Staff claims SDG&E has failed to identify the technology which would be used at Blythe. It believes this affects the amount and timing of generation capacity which would be available to SDG&E, the type of capacity, that is, base-load or peaking, and the cost of any capacity.

Staff presented witness Fukutome who claimed that SDG&E's showing in this proceeding is less definitive than the showing made in the two previous general rate cases. In those cases, according to Fukutome, late 1980 or early 1990 dates were discussed as project completion dates. However, SDG&E now concedes a possible slippage to 1995 or beyond. Under these circumstances, Fukutome claims that Blythe should not qualify for PHFU treatment because its potential use is so far out in the future.

Witness Kansal for the staff testified that reliance by SDG&E on its resource planning is not a good basis for measuring the future operational needs of a utility. He claims that by following such plans California utilities have found themselves in the situation of capacity excesses caused by gross-over estimates of electric demand.

Staff claims that the company has not given enough weight to the Southwest Power Link project for future base-load needs. Staff believes that contracts under which capacity is or would be available to SDG&E over the Soutwest Power Link are not presently included in SDG&E's resource mix beyond 1988. Staff feels that not enough consideration has been given to the proposed projects shown on Table 5. It believes that the progress of any of these projects could affect SDG&E's need for Blythe generating capacity in three ways. First, SDG&E could participate as a partner; second, development of the projects might increase the availability of capacity through the Southwest Power Link; and third, it is doubtful that potential partners of the Blythe site would be developing their own projects in addition to Blythe.

Staff claims there is no guarantee that the estimate offered by Mao of $200 million to replicate the site at 1982 dollars would be the figure that a consortium would agree to in negotiating with SDG&E for acquisition of the site much less an assignment to SDG&E of $435 million in 1992. Staff believes the $200 million 1982 valuation may not stand up when it comes time to negotiate a value with members of a consortium. Staff feels this is particularly brought home by the fact that it appears SDG&E is willing to sell the site at the present time for as little as $30 million, about one-seventh of its replication value.

Staff criticizes the idea that all of the licensing has been accomplished. They point out that the Sundesert work was for a nuclear generating facility and that an SDG&E witness admitted that a completely new environmental review would have to be presented to different regulators prior to obtaining a construction permit for other than a nuclear operation. The staff brought out that if SDG&E's ultimate partners placed a value of $66 million on the Blythe asset rather than the $200 million estimated by Mao, ratepayers would receive no economic benefit from the continued ratemaking recognition.

Staff clarified its position in the staff brief concerning the Blythe site and whether or not it should be sold. Staff states that it is recommending the Commission deny ratemaking recognition of Blythe expenditures until such time as SDG&E provides justification for PHFU treatment as the Commission required in D.93892. Staff witness Fukutome stated explicitly that the staff recommendation is a two-year recommendation and should last until SDG&E's 1986 test year when the staff would take a fresh look at what the company proposes for Blythe. Witness Cotton for SDG&E testified that 1985 would be the year by which more explicit Blythe plans could be developed. Staff feels confident that SDG&E may be able to meet such a burden of proof in the near future but in this particular rate case, it has not. Staff advises all parties that the ratemaking treatment accorded the Blythe assets has no bearing on whether SDG&E may or may not sell the Blythe site, something the staff is not recommending. Staff points out that even though a public utility may sell assets not used or useful to its utility operation this does not mean that a number of subsidiary post-sale inquiries are precluded. For instance, the Commission retains jurisdiction over the sale proceeds and may make appropriate orders concerning the distribution of gains or apportionment of losses between ratepayers and shareholders. At the oral argument, staff took the position that even if the Commission were to exclude Blythe from rate base and SDG&E were to sell the site, the Commission could examine SDG&E's action for prudency in some later proceeding.

13.10.6 Position of the City of San Diego

San Diego recognizes that the company made an extensive showing regarding the potential value of the site. However, San Diego questions whether it has been shown there is a specific plan for using the site. San Diego points out in the record the following exchange, (RT: 1277-8) which in the opinion of San Diego indicates that SDG&E has only a specific "plan for a project" not a project.

> "Q. So it's correct, is it not, at this point in time you have not selected what type of power plant there will be?
>
> "A. Yes.
>
> "Q. And at this point in time you don't know who the lead utility for this project will be, is that correct?
>
> "A. Yes.
>
> "Q. And at this point in time you don't know who will own what percentages of this proposed plant, is that correct?
>
> "A. Yes.
>
> "Q. So I understand what you are saying, Mr. Cotton, I believe you have indicated a couple of times that what SDG&E has is a specific plan for the Blythe site but not a specific project, is that a correct assessment of what you have told us this morning?
>
> "A. That's right.
>
> There is no project at this point in time.
>
> "ALJ PORTER: But your specific plan is to have a project?
>
> "THE WITNESS: Yes, sir.
>
> "ALJ PORTER: Is that the way it follows?
>
> "THE WITNESS: Yes, sir."

San Diego claims that having a specific plan to develop a specific project is not what the Commission had in mind in D.93892.

San Diego, like the staff, believes the basic issue on Blythe in this case is a ratemaking issue and no party in the proceeding has recommended that the site be sold. San Diego concedes that the site is a valuable asset, however, the question is whether the ratepayer should pay somewhere between $9 and $11 million a year for the retention of the site in rate base.[2] The specific plan D.93892 ordered is, according to SDG&E, satisfied by having a specific plan to develop a specific project. San Diego submits that this play on words does not meet the requirements of D.93892. San Diego also claims that SDG&E has not carried this burden of showing that a plant at the Blythe site will actually be needed in the 1990's.

San Diego brings in a unique argument which turns SDG&E's quantifying added uncertainty (QAU), method of determining depreciation against the Blythe site. (See Section 12.) San Diego finds an inconsistency in the fact that the company has increased its depreciation by decreasing the life of some of its assets in order to take care of four factors which may shorten the lives of those assets:

1. Competing technologies.
2. Environmental constraints.
3. Increased purchases of energy from eastern states.
4. Insecurity of fuel supplies.

San Diego believes that if SDG&E is serious about its QAU arguments, then it cannot be serious about needing electric generation at the Blythe site in the early to mid-1990s.

San Diego's primary recommendation concurs with the PUC staff recommendation that the $45 million currently in rate base should be removed for ratemaking purposes until SDG&E has a specific

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2 The record shows it takes about $11.9 million to support the Blythe site in rate base at the 14.93% rate of return originally requested by SDG&E.

plan for the site and can show that the potential capacity from the site will be needed by SDG&E in a specified time frame. San Diego urges the Commission to make clear that SDG&E can ask to include the Blythe site as PHFU in its 1986 general rate case if it has met the requirements of D.93892. San Diego also urges the Commission to make very clear in its decision that if SDG&E sells the site and water rights for agricultural purposes, and at some time later needs to build additional capacity, that the difference between the sale price and the cost of acquiring a new site will be closely examined for prudency.

If the Commission decides to keep the site in rate base, San Diego's secondary recommendation is one of staff witness Grove's alternatives. San Diego would prefer to see the $45 million split into $19.5 million for land and land rights, and $25.5 million for nonland and nonwater rights. The $19.5 million would be placed in rate base as PHFU and earn a return of 10.59 precent, and the $25.5 million would be amortized over four years.

13.10.7 <u>Position of Welfare Rights Organization</u>

WRO's position is that the Commission must exclude the Blythe site from rate base to be consistent with D.93892 in SDG&E's last general rate case. WRO maintains that SDG&E does not have a plan for use of the Blythe site. WRO claims that SDG&E has failed to provide evidence of little more than an indication that the Blythe site might be a future power plant location.

WRO claims that the Bechtel study suggests seven possible technologies as suitable for the site, none of which SDG&E has committed itself to. Not only is SDG&E ignorant of the type of power plant it plans to build on the site, it has no partners in the venture. WRO believes it is certain that SDG&E does not intend to build a plant on the site without partners and does not intend to be the lead utility for the site. WRO believes that all SDG&E has done toward identifying and committing partners in the development of the site is to hold a few meetings attended by 17 utilities. Two of the utilities offered some technical support but none of the others have offered anything more than a few words of encouragement.

WRO believes the more than $400 million value that the Woodward-Clyde study was escalated to for 1992 is a highly unlikely figure to be accepted by a consortium of utilities as SDG&E's valuation of the site and its contribution. In summary, WRO claims the gist of SDG&E's definite plan for the Blythe site is the construction of an unknown type of power plant by several unknown utilities led by an unknown utility which will hopefully accept SDG&E's valuation of the site at over $400 million as its sole contribution to the cost of a new power plant with commercial operation of the first unit to be some time in the 1990's. WRO submits that all of these chances are too uncertain. To require current ratepayers to be risk-takers but guaranteed no compensation for that risk is radically opposed to the traditional roles of investor and ratepayers. The only reason property held for future use should be in rate base is if there is a definite plan for its use. WRO believes that if the Blythe site is removed from rate base, it will be an incentive for SDG&E to come up with a definite plan for its use.

13.10.8 Position of the California Energy Commission

CEC called its General Counsel, William M. Chamberlain, to introduce a statement of position adopted by the CEC on April 20, 1983. The CEC position is that absent a reevaluation by the CEC of the questions pertaining to the need for additional generating capacity and in particular the need for SDG&E to retain the Blythe site, the Commission should not take action which would require SDG&E to eliminate the Blythe site from its resource plan.

13.10.9 Position of Other Parties

The San Diego City Council and the San Diego Coalition urge the Commission to retain the Blythe site as a potential power plant facility, but make no recommendation concerning its treatment for ratemaking purposes.

13.10.10 Discussion of the Blythe Site

Based on the assumptions used in the record to evaluate the Blythe site there is a clear economic advantage to ratepayers of retaining the site in rate base. However, these assumptions are as follows:

1. The site would need no further licensing.
2. There would be no change in the water rights and water access that exist today.
3. The value of the site today, if sold for agricultural purposes, is about $30 million.
4. The 1982 value of Blythe as a power plant site is $200 million.
5. The value as a power plant site in 1992 will be $435 million.
6. The cost per kilowatt of power for a power plant in 1992 will be $3,000.
7. SDG&E will need a total of 625 megawatts of power from the site beginning with 125 megawatts in 1992 and adding 125 megawatts in each even year thereafter until the year 2000.
8. A consortium will be formed to develop the site and have it operating by about 1992.
9. San Diego Gas & Electric will not be the lead utility in the consortium.
10. The consortium that would build a power plant on the site would accept as SDG&E's contribution toward those facilities the value of the site at $435 million in 1992.

As clearly shown on the record, if all of the above assumptions are correct, the site has a definite economic advantage for ratepayers.

SDG&E has held meetings concerning the Blythe site in both Los Angeles and Phoenix. At Los Angeles, representatives of Southern

California Edison Company, the municipally-owned organizations of Anaheim, Glendale, Pasadena, Burbank, and Riverside, the Los Angeles Department of Water and Power, and the State Department of Water Resources were briefed on the site. At the meeting held in Phoenix, representatives of Arizona Public Service Company, Nevada Power Company, Tucson Electric Power Company, the Sacramento Municipal Utility District, the Western Area Power Administration, Pacific Gas & Electric Company, the Salt River Project, Sierra Pacific, and Public Service Company of New Mexico were advised of developments. The company maintains that all of these representatives express support for maintaining the site. What bothers us a great deal is that, at the urging of the ALJ, SDG&E could prevail upon only two of these 17 organizations to attend the hearing and make statements concerning their interests in the Blythe site. It is clear from the record that if the Blythe site were developed as anticipated by SDG&E in this proceedings, one of these utilities would become the lead utility in the project. Probably, many of them would also participate. Witness Roemmelt cited seven utilities which anticipate generation needs in the 1990's that could be served by a facility at the Blythe site. Five of these were at the Los Angeles or Phoenix meetings. The two utilities that did appear at the hearing - Edison and APS - were at best lukewarm about committing themselves to either the project or a lead utility position. We have to wonder where support for the project will come from if no more interest than that is shown. The representative from Edison testified that Edison had not considered Blythe as anything other than a potential site of some modest interest to the company. The witness for APS said that APS would only be interested in keeping open an option to participate in a Blythe project. When asked if APS would agree to give SDG&E a $200 million credit towards the development of a Blythe project in which it would be involved based on 1982 dollars, the witness said he would probably negotiate, but SDG&E would probably be entitled to something greater than the $30 million valuation.

If the Blythe site is left in SDG&E's rate base, SDG&E ratepayers will, of course, have to support the site until the first energy might be generated which could be as early as 1992 and more likely 1995, according to this record. Staff witness Grove indicated that if the ratepayers were to support the site between now and 1992 at the 10.59 percent rate of return that is presently being earned on the $45 million, the ratepayers would have contributed a total of $144 million toward the site. If the site were to sell for the equivalent of $435 million, this would of course be a bargain. But that is certainly questionable based on this record and the attitude of the possible participants.

Other of the assumptions underlying SDG&E's presentation on the Blythe site are also questionable, and the support offered for those assumptions is based on additional assumptions that raise further questions. SDG&E argues that the site is an unrivaled location for a power plant and possesses a worth far in excess of its current market value, but this argument is undercut by other utilities' lack of interest in the site and by SDG&E's own reluctance to take the lead in developing the site.

We are concerned that SDG&E's ratepayers continue to carry the costs of this property under such uncertain circumstances and we are further concerned that we have heard no plan for relieving them of this cost burden while preserving the benefits of the site for California generally.

Accordingly, we will reserve this issue for resolution after further hearings to be scheduled in early 1984 at which time we expect to hear from SDG&E, staff, other parties and members of the potential consortium which might build a power plant on the site as to what ratemaking treatment of the Blythe site would most equitably balance the interests of SDG&E, its ratepayers and California generally. We will circulate separately the alternate proposal of Commissioner Grew for treatment of this site which was discussed at length at our conference on December 20, 1983. We will expect parties to address this alternative specifically.

Pending our decision on this issue, we will maintain the status quo for the site established by D. 93892. SDG&E will retain the $45 million site in rate base, earning a rate of return on it of 10.59%.

13.11 Profit from Sorrento East Property Sale

In 1966 SDG&E purchased what is known as the Sorrento East Property as a potential power plant site. The property is located approximately 18 miles north of San Diego. Because there were no general rate cases between 1966 and 1972, the value of the property was included in SDG&E's rate base for ratemaking purposes for the first time in 1972. At the suggestion of the Commission staff, the property was removed from rate base in 1976 because it was not needed as utility property, and SDG&E had no definite plan for its use as a site in SDG&E's operating plans. In 1982, SDG&E sold the property for $4,150,393. Based on a recorded asset value of $1,775,277, SDG&E realized a capital gain of $2,375,116. In 1982, SDG&E booked to electric revenue a portion of that gain which is considered to be applicable to ratepayers. It calculated that amount on the basis that during the 196 months that the property was owned, it was in rate base for 58 months. Therefore, SDG&E allocated 58/196ths of the $2,375,116 to its utility operation.

A staff witness recommends that the entire gain on the sale be flowed through to ratepayers. He based his recommendation solely on an application of the uniform system of accounts. He stated that if a loss had been incurred, he would likewise recommend that loss be passed through to the ratepayers. Staff counsel in his brief argues that this Commission employes a risk of loss methodology in allocating gains from the sale of utility plant and sites. He gave D.82-12-121 in OII 82-05-01 dated December 30, 1982 as his authority. However, we note in that decision at page 23, the following:

> "We agree with the parties that risk analysis should be the major consideration underlying the allocation of the gain (or loss) between shareholders and ratepayers. While there are several Commission decisions that do apply this principle, each major abandonment problem should be reviewed on an individual basis. Therefore, we consider these other decisions informative but not dispositive of the way risk is shared."

There is no question on this record concerning the propriety of the Sorrento East Property in the rate base, that was decided in 1972 and in 1976. We will adopt San Diego's position and allocate the gain on the basis of the time that ratepayers and shareholders were at risk.

14. Rate of Return

For 1982 and 1983 test years, the Commission granted SDG&E 12.92% and 13.25% rates of return. These included a return on equity of 16.25% and reflected incremental bond costs of 16% for 1982 and 14.5% for 1983, respectively. A significant development during the hearing phase of these proceedings was the upgrading of SDG&E's bonds in May and early June of 1983 from B+/Baa to A- rating. The company had as its long-term goal an upgrading sometime in 1984. Similarly, in making its determination for 1982 test year, the Commission assumed that "this goal cannot be achieved in 1982 or 1983" (D.59788 mimeo, p. 26).

There have been several changes in the recommendations on rate of return during the course of these hearings, including updates made at the hearing in September, 1983. In the company's NOI and application which were filed in the fall of 1982 and late December 1982, respectively, SDG&E asked for a rate of return of 14.93% in 1984 and 15.34% in 1985, with a requested return on equity of 19%. SDG&E estimated a cost of 16% and 15¼% for new bond issues in 1984 and 1985, respectively. At the prehearing conference on February 3, 1983, SDG&E reduced its request to 14.05% overall and a 17.5% return on equity to reflect improved market conditions.

In June and again in September 1983 the company issued \$150,000,000 in industrial development bonds (IDB)[3] at favorable interest rates of 10.56% and 10.50%. In its final update exhibit, SDG&E reflected these issuances in its embedded costs for 1984, and revised its request to reflect no new debt financing for 1984. This caused it to reduce its request further to 13.44% overall, with a 17.5% return on equity. The combination of these changes has reduced SDG&E's revenue increase request from its original amount of \$126.8 down to \$65.3 million for test year 1984.

For 1985, SDG&E reduced the amount of new debt financing from \$162 to \$100 million, but at the same time increased the cost of new issuances to 15 3/8%. The result, with no change in the requested cost of equity, was a 13.88% composite return for the attrition year.

Table 7 shows the latest company request, and the recommendation by the staff. The only other recommendations concerning rate of return were made by Federal Executive Agencies (FEA) and the California Association of Utility Shareholders (CAUS). FEA recommended the return on equity be 14% to 15% and CAUS 18%.

[3] Backed by the government these bonds are issued at interest rates generally 300 basis points below market.

Table 7

Recommended Rate of Return - 1984

SDG&E

	Capitalization Ratios	Cost Rates	Weighted Costs
Long-Term Debt	45.84%	10.51%	4.82%
Preferred Stock	11.55	10.08	1.16
Common Equity	42.62	17.50	7.46
Total	100.00%		13.44%

Staff

	Capitalization Ratios	Cost Rates	Weighted Costs
Long-Term Debt	45.50%	10.50%	4.78%
Preferred Stock	11.50	10.08	1.16
Common Equity	43.00	16.00[4]	6.88
Total	100.00%		12.82%

Recommended Rate of Return - 1985

SDG&E

	Capitalization Ratios	Cost Rates	Weighted Costs
Long-Term Debt	42.93%	10.88%	4.67%
Preferred Stock	10.63	10.11	1.08
Common Equity	46.45	17.50	8.13
Total	100.00%		13.88%

Staff

	Capitalization Ratios	Cost Rates	Weighted Costs
Long-Term Debt	45.50%	10.74%	4.89%
Preferred Stock	11.50	10.10	1.16
Common Equity	43.00	16.00[4]	6.88
Total	100.00%		12.93%

4 Midpoint of staff's recommended range (15.75% - 16.25%).

14.1 Capitalization Ratios

There is very little difference between the company and the staff capitalization ratios. The primary difference is in common equity where the staff has included 43%, which is the goal of SDG&E in the short term. The preferred stock figure is almost the same for both the staff and the company, which leaves the long-term debt ratio as a residual, it being a function of 100% minus the common equity and preferred stock percentages. There was some comment during the hearing concerning the inclusion of bankers' acceptances in SDG&E's capital structure. The staff proposed that they be removed because the ECAC mechanism currently compensates SDG&E for the carrying cost of fuel oil inventory, that being the short-term financing purpose of the bankers' acceptances. By stipulation, bankers' acceptances have been excluded by SDG&E and the staff in favor of consideration of their ratemaking treatment of fuel oil inventory carrying costs in OII 82-04-02, the ECAC incentives case.

We will adopt the staff's capitalization ratios because it should give the company more of an incentive to achieve its announced goal of a 43% ratio for common equity.

14.2 Long-Term Debt and Preferred Stock Costs

Long-term debt and preferred stock costs are a function of the cost, quantity, and timing of planned financings and/or retirements. In general, staff and SDG&E agree on the overall dollar level of financings to occur in 1984 and 1985, with minor differences as to the timing of those financings. We will adopt staff figures to be consistent with the adoption of its capitalization ratios.

In terms of the cost rates for these issuances, staff's recommendations reflect lower incremental debt costs for 1984 and 1985 than SDG&E's request. Staff's estimate of 13% was based on a review of historical data and interest rate forecasts for AA rated bonds published by Data Resources, Inc. (DRI), adjusted to reflect historical bond rate spreads between AA and Baa rated bonds. SDG&E also based its estimates of incremental debt costs on DRI forecasts and historical yeild spreads, but then incorporated a 300 basis point "error premium" in deriving its 15 3/8% projected cost of incremental debt. We do not consider the error premium adjustment a defensible approach to estimating incremental debt costs, nor do we find the results of that approach reasonable. We adopt staff's estimates of incremental debt costs in our authorized rate of return.

14.3 Return on Equity

One of the most significant, and perhaps the most difficult, factors to determine in a rate case is return on common equity. In addition to presenting quantitative and qualitative analysis on the cost of equity capital, parties to this proceeding also presented testimony on the policy considerations this Commission should take into account in establishing a fair and equitable rate of return. Before describing and evaluating the specific recommendations presented by parties, it is important to reiterate, and perhaps clarify our policy objectives in this area of ratemaking.

Simply stated, our objective is to authorize a return to common equity owners that will be commensurate with the market returns on investments having corresponding risks during the test period. We believe that, in establishing an authorized return which appropriately reflects the market cost of capital, we are placing utility management on a sound financial footing in terms of competing for and attracting capital. This does not mean, however, that SDG&E or any utility will necessarily earn its authorized rate of return during the test year--that depends on the ability of SDG&E's management to effectively and efficiently utilize its resources over both the short- and long-term, and the reasonableness of the expense estimates and allowances for the test period.

We view the rate of return portion of this proceeding as part of the overall process of prospective ratemaking. As we have discussed in establishing test year revenue requirements for other expense categories, prospective ratemaking does not "look back" in time and adjust future revenue requirements such that actual utility expenditures are always recovered 1-for-1 through rates. If utility management decides to trade-off among expense categories in response to changing circumstances or management priorities, they are awarded that flexibility.

However, prospective ratemaking does not provide cost recovery in future years for activities that were budgeted for, but not performed in previous test years. Nor does prospective ratemaking require the utility to reimburse ratepayers if their overall expenditures, or expenditures within particular budget categories, are lower than projected during the rate case. To do so would be tantamount to establishing a 1-for-1 balancing account for all utility expenditures and activities.

Similarly, we believe it is inappropriate to establish a higher rate of return for a prospective test year in order to compensate utility shareholders for the fact that utility earnings were lower than the authorized rate in previous years. Nor do we expect shareholders to reimburse ratepayers directly (or indirectly by depressing future authorized returns) when the utility earns in excess of its authorized rate of return.

The task before us, then, is to estimate the cost of SDG&E's equity capital in the market over the next two years. To do so, we must identify the risks for which investors require compensation, evaluate the relative magnitude of these risks for SDG&E over the test-year period, and quantify these observations into an authorized rate of return on common equity and total capital. We are guided by three major considerations.

First, we believe that, all other things being equal, the cost of equity capital varies in the same direction as changes in the general level of inflation and interest rates. Although the absolute magnitude of that relationship or "risk premium" is an issue of controversy, the general principle is not only consistent with financial theory, but also acknowledged by this Commission and parties to this and prior rate of return proceedings.

Second, we recognize that the market cost of equity capital for a particular company reflects other risks, such as the exposure of a utility's earnings to variability in fuel costs, sales levels, as well as uncertainties regarding the cost recovery of prior capital investments. Hence, our determination of an appropriate rate of return must also take into consideration the extent to which these risks have abated, increased or remained unchanged, and the probable direction of change during the test year period.

Finally, we believe that the judicious application and interpretation of financial models can aid us in quantifying the overall balance of these risks, and the market cost of equity capital during the test period. It must be emphasized, however, that the models themselves may not accurately reflect all of the intricacies of financial markets. Further, the assumptions used in applying a financial model or formula must be carefully evaluated for reasonableness before this Commission places substantial weight on the numeric results.

14.3.1 Summary of Positions

The issue of the appropriate rate of return on common equity was contested by four parties in this proceeding. Each party estimated a range of costs using one or more financial modeling techniques. The results of their analysis and their recommendations are summarized below:

Party	Range of Results	Recommended Return On Common Equity
CAUS	--	18.0%
SDG&E		
--application	18.53% - 20.05%	19.0%
--updated (9/83)	16.30% - 18.65%	17.5%
Staff	15.61% - 16.46%	15.75% - 16.25% (16.00% midpoint)
FEA	13.69% - 15.00%	14% - 15%

14.3.2 Position of SDG&E

SDG&E presented two witnesses in support of its position, Robert Korpan, Vice-President of Finance for SDG&E, and Eugene W. Meyer, Vice-President and Director of Kidder Peabody and Company, Inc.

Witness Korpan made the most comprehensive presentation for SDG&E in attempting to demonstrate the reasonableness of SDG&E's requested 17.5% return on equity. He based his equity return recommendation on three specific approaches: the risk premium method, a discounted cash flow analysis, and a market-to-book ratio approach for comparable risk companies.

Risk premium is a method that assumes the common equity investor demands a premium above returns received by the bondholder in order to compensate the investor for additional risk. Korpan estimates a risk premium using historical differences between earnings-price ratios (as a cost of equity proxy) and Baa bond yields. He derives a 4.08% average risk premium from the most recent 5-year data. The risk premium is applied to projected costs of new debt, which incorporate the 300 basis point error premium discussed above.

The results of this analysis yield a 17.81%-18.65% return on equity. Korpan confirms these results by similarly calculating a historical risk premium between SDG&E's earnings price ratio and yields on 3- to 5-year government bonds. This calculation produced a range of 16.30%-18.44%.

Korpan also used a discounted cash flow (DCF) method in estimating the cost of equity capital. The DCF approach assumes that, along with a certain return in the form of a dividend yield, an investor expects future earnings' growth from that investment. Assumptions concerning the company's 1983 dividend yield and earnings growth rate are critical in the application of this model.

First, Korpan calculated a dividend growth rate of 6.19%, based on 1976-1981 dividend growth. He then developed two sets of dividend yields, the first based on 1982 actual declared dividends and stock price and the second based on a regression formula. For the first calculation, he used the 1982 declared dividend of $1.82 dividend by an average December 1982 price, for a dividend yield of 10.51%. This dividend yield, added to the 6.19% growth rate resulted in a 16.70% return on equity.

For his second DCF estimate, Korpan repressed SDG&E's actual average dividend yield against the Aa utility bond yield for the most recent 24-month period (through April, 1982). The resulting regression formula was used as a basis for estimating SDG&E's 1983 dividend yield. DRI's projection of new debt costs (adjusted upwards for an error premium) was plugged in as the independent variable to yield a 1983 dividend yield of 12.15%. Using this method, Korpan arrived at a projected cost of 18.34% for common equity.

Finally, Korpan applies a market-to-book ratio formula to a sample of 10 utilities he considers comparable to SDG&E in risk. The market-to-book ratio method calculates the rate of return on common equity that will equate the current market and book values of a utility's common stock. It is based on the theoretical premise that, if the company is earning its market cost of equity capital, the market-to-book ratio of its stock should equal 1. Application of the formula, however, adjusts prospective authorized rates of return such that this equality will hold during the test period. Based on this formula, Kaplan adjusts the 1981 realized returns of his sample (12.59%) for a resulting cost of equity of 18.53%.

In addition to his quantitative analysis, Korpan also identified in qualitative terms certain "offsetting policies" of this Commission, that have generated substantial additional risk to SDG&E, as perceived by the financial community. Specifically, he referred to the SONGS 1 sleeving cost decision, which allowed the company to recover costs subject to additional review; recovery of Tesoro underlift charges subject to additional ECAC reasonableness review, continued uncertainty with regard to ratebasing of the Blythe site; discussion of alternative ratemaking procedures/performance criterial in the SONGS 2 MACC proceeding, the AER/ECAC split decision, which removed 8% of SDG&E's fuel-related costs from the ECAC balancing account mechanism and the ERAM billing lag decision, which adjusted ERAM tariffs to eliminate imputing January rates for services rendered during the prior month of December.

Korpan recommends a 17.5% return on equity, which corresponds to the midpoint of his 16.3%-18.65% range of quantitative results. Witness Meyer made a presentation on what he believes the current market conditions reflect in attempting to support witness Korpan's 17.5%. In particular, Meyer used the market-to-book ratio method to calculate that a 17.5% return on equity, given market conditions as of mid-1983, would equate SDG&E's market-to-book values. Both witnesses emphasized what they believe to be the severe impact of higher costs on SDG&E's ratepayers due to past bond downgradings, common stock dilutions, and lack of financial community support.

14.3.3 Presentation of the Commission Staff

The staff presented witness Edward Quan, a financial analyst from the Commission's Revenue Requirements Division. Witness Quan provided results of the risk premium, discounted cash flow, and comparable earnings approaches in presenting his recommendations.

Quan's risk premium approach examined the 10-year period made up of two consecutive 5-year periods, 1973 through 1982. He compared SDG&E's earnings price ratio to A-rated bond yields between 1973 and 1974 and Baa-rated bond yields from 1975 to 1982. On this basis he determined that between 2.61 and 3.46 percentage points should be added to his 13% estimate of long-term debt cost for 1984 and 1985 to obtain the estimate of return on equity. The result was a range of 15.61% to 16.46%.

For his discounted cash flow analysis, Quan projected a 11.23% 1983 dividend yield, based on the average yields observed during the last 6 month of 1982. He examined historical growth in dividends, earnings per share and book value per share over the 1972-1982 period to arrive at a 4.5%-5.5% annual growth rate. In addition, he estimated SDG&E's sustainable growth rate to be 4.65%-4.80% based on his projections of retained earnings. Based on this analysis, Mr. Quan argues that the higher growth rate in dividends observed over the most recent 5-year period overestimates growth in earnings. The result of his analysis indicated that SDG&E's cost of common equity ranges from 15.73% to 16.23% using historical growth rate assumptions and 15.88% to 16.03% using sustainable growth rates.

As a test of reasonableness, Quan extended his DCF analysis to 15 companies to compare his company-specific results to utilities of comparable risk. The results of his DCF analysis for a sample of comparable companies yields a cost of equity capital between 14.85%-16.72%, with an average return of 15.77%.

Quan concludes that an authorized return on common equity of 15.75%-16.25% would fairly compensate investors in SDG&E's common stock for returns foregone by not pursuing investments of comparable risk. In developing his recommendation, Quan considered other factors that should have a positive impact on SDG&E's financial performance during the test period, including an increase in its common equity ratio, improvement in its level of internal cash generation and completion of major construction projects which should lower the level of internal cash generation. Mr. Quan testified that he felt this overall tange was still appropriate, even in light of the upgrading of SDG&E's bonds announced subsequent to preparation of his testimony.

14.3.4 Presentation of FEA

The FEA called Basil L. Copeland, Jr. as its witness on cost of capital. Copeland used variations of the discounted cash flow method to estimate the cost of common equity. Copeland used the basic approach of determining the total required return as the combination of required dividend yield plus the expected earnings growth rate. Copeland used several methods to determine his final estimate of between 14% and 15% as a fair return on common equity. His analysis included consideration of the returns on 97 of the 106 electric utilities on the New York stock exchange. He considered the utilities to be a homogenous group and conceded that if he were to make a recommendation for any of the 97, of which Edison, PG&E and SDG&E are included, he would recommend the same rate of return on common equity regardless of any differences in bond ratings.

14.3.5 Presentation of CAUS

The California Association of Utility Shareholders sponsored Philip C. Presber as its witness. Presber made a recommendation only on a fair return on common equity which he judged to be 18%. To derive his recommendation, Mr. Presber calculates the earnings per share and dividends, and the resulting book value required to maintain an earnings price ratio recently experienced by SDG&E. This approach is similar to market-to-book ratio formulas, where market performance goals are set and a rate of return necessary to achieve that goal is derived. This calculation yields a return on equity of 17.5% for 1984 and 1985. Mr. Presber recommends an overall return of 18%, which is higher than that of any other party to this proceeding (including SDG&E), to "compensate for investor expectations regarding earned versus allowed returns and for the issuance of new shares" (Exhibit 85 p.33).

Presber believes that SDG&E has had a long history of lower than required returns on common equity. He sees from this a result which has not allowed SDG&E shareholders a fair return on their investments since 1972. He notes that the market value of SDG&E shares has been below book value for many years. He claims that since 1972, if calculated on the basis of the total shares offered each year, SDG&E has sold 37 million shares of common stock below book value. The result of this dilution was that the 10-year average, 1973 to 1982, calculated return on common investment of 11.5% was actually a mere 8.1%. Thus, the earnings per share by conventional calculation overstates the actual earnings by 42%. (See Exhibit 85, Table II, Column H.) CAUS believes all this has an adverse impact on consumers by raising the cost of capital through a lowering of SDG&E's bond rating.

CAUS recognizes the progress being made on many fronts financially for SDG&E and applauds the Commission, its staff, and the management of the company for this, but it maintains that if this momentum is to be maintained, a return of 18% on common equity is required. CAUS believes the 18% it recommends on common equity will enable the company to continue to earn its authorized rate of return as it has for approximately the last 6 months, and enable it to sell common stock at or above book value.

14.3.6 Position of the City of San Diego

San Diego made no direct presentation on rate of return but through cross-examination and its brief brought out its position. San Diego maintains that the current return on equity of 16.25% was set by the Commission when the prime rate was about 20%, inflation was in double digits, and interest rates on corporate securities were around 16% or more. It argues the Commission did not believe SDG&E could achieve an A rating in 1982 or 1983 when it set the return on equity at 16.25%. However, San Diego points out the company did, in fact, achieve its A rating in the middle of 1983, at which time SDG&E was earning about a 15.8% return on equity.

San Diego believes there is no support for SDG&E's requested 17.5% rate of return in view of the fact that its stock is selling above book value and its ratings have beeen improved by both Standard and Poor's and Moody's. The Commission authorized a 16.25% rate of return in the last proceeding in spite of the fact that SDG&E was requesting 19%. The company is currently making 15.8% return from a ratemaking standpoint and 17% from what witness Korpan describes as a financial standpoint, and, finally, interest rates have softened somewhat since 1981.

San Diego submits that the Commission should take all of these factors into account and recommends that a rate of return on common equity be set in the vicinity of 15% for the test year 1984.

14.3.7 Position of Welfare Rights Organization

WRO's position is that the record indicates the Commission should not grant a rate of return on equity higher than the 16.25% granted in the 1982 general rate case. It contends that the record indicates a lower return could be authorized. WRO bases its recommendation on the improvement in all financial aspects of SDG&E's operation which have been shown in this proceeding.

WRO, in commenting on the specific recommendations of the parties, believes that SDG&E has totally failed to take into account current conditions in making its recommendation of a 17.5% return on equity. The staff's recommended return suffers from the use of outdated data and the recommendation of federal executive agencies of 14% to 15% is sufficient. WRO believes the interests of SDG&E's ratepayers have been sidelined by the Commission in its overzealous support of SDG&E's pursuit of an improved financial condition. It believes that now that the ratepayers have brought SDG&E its desired credit rating they are entitled to reap the promised benefits, a decreased cost of capital and the consequently lower rate of return.

14.3.8 Discussion

In evaluating the return on equity recommendations, we will first evaluate the quantitative analysis presented in this proceeding, highlighting the strengths and weaknesses in input assumptions and modeling techniques. This discussion will serve to narrow the wide range of returns presented in this proceeding to a range which we feel best represents the judicious application of financial modeling techniques. Second, we will evaluate the qualitative discussion of risk presented by the parties, in order to determine where within that range SDG&E's market rate of return lies. Our final determination will reflect our best judgement concerning the relative weight of all the factors presented in this case.

With regard to the quantitative analyses presented by PG&E, FEA and CAUS, we place very little weight on the results of market-to-book ratio analysis, where a required rate of return is "derived" by equating market-to-book values or by establishing a target earnings-price ratio. Due to powerful external factors in the market which affect stock price, we find that use of a market-to-book ratio formula provides little or no practical guidance in estimating, prospectively, a market rate of return. We are putting parties on notice that, in future rate of return proceedings, the results of a market-to-book ratio method will have little weight in our determination of rate of return.

As discussed above, we also question the reasonableness of Mr. Korpan's "error premium" adjustment to DRI forecasts of bond rates. We note, for example, that the adjustment was based on forecasting errors observed for a very limited, and highly volatile period, during which interest rates were increasing dramatically. Unfortunately, this upward adjustment permeates almost every return on equity calculation made by Mr. Korpan, including his DCF calculations. We are also persuaded by staff's and Mr. Copeland's observations that Mr. Korpan's use of SDG&E's recent 5-year dividend growth over-estimates the expected growth rate in earnings. In sum, we find that Mr. Korpan's choice of input assumptions and modeling techniques significantly biases the resulting return on equity upwards.

With regard to Mr. Copeland's presentation, we consider the usefulness of his analysis very limited, since it is based on observations of utilities as a homogenous group. The 14%-15% recommended by FEA is based on what the record shows to be an average of a large cross-section of electric and gas utilities in the United States. The recommendation of FEA would be applied to those utilities, regardless of their relative risk. We reject that approach as being too simplistic for the conditions at SDG&E.

Turning to staff's presentation, we find that Mr. Quan clearly explained and supported his choice of assumptions based on a combination of financial theory and common sense. We believe that the results of staff's quantitative analysis provide us with the most supportable range of results, 15.6%-16.5%, as a guide for determining SDG&E's authorized return on equity.

In addition to presenting quantitative analysis, witnesses in this proceeding presented a considerable amount of qualitative information concerning the risks facing SDG&E relative to other utilities, previous years and future trends. We consider this qualitative assessment to be very important in our final determination. As indicated above, the range of reasonable results based solely on the quantitative analysis is from an increase in SDG&E's current authorized return of approximately 25 basis points to a decrease of approximately 65 basis points. Our final determination must reflect our best judgment as to the magnitude and direction of risks facing SDG&E over the next 2 years.

First, we turn to Mr. Korpan's argument that the financial community perceives substantial additional risks during the test year due to certain "offsetting policies" of the Commission. As Mr. Korpan conceded in cross-examination, decisions relating to all of the policies he identified were made <u>prior</u> to the time that rating agencies upgraded SDG&E's bonds (Tr. 4579-4580).

Furthermore, we find that our ratemaking procedures protect the utility's earnings from a whole range of variables, including fuel price, fuel mix, sales level, inflation and the timeliness and predictability of regulatory rate recognition. Specifically, the Purchase Gas Adjustment Clause (PGA) insures that the utility will collect in rates all increases in the cost of gas supplies through the use of a balancing account; the ECAC procedure insures that SDG&E will collect in rates 91% of any unforecasted increase in the cost of electric generation due to increases in fuel cost and/or fuel mix by use of a balancing account; rate base offset proceedings, allow the utility to file immediately for a rate increase upon the completion of a major plant addition, rather than waiting for the next general rate case; the rate case plan guarantees the utility timely processing of general rate case applications at regular intervals which recently required updating of data at the end of the public hearings, and the Supply Adjustment Mechanism (SAM) proceeding guarantees that the utility will be compensated for its margin on natural gas sales that may be lost due to sale fluctuations. We also note that, since SDG&E's last general rate case, two additional regulatory mechanisms have been put into effect: the Attrition Rate Adjustment (ARA) procedure, which provides for an automatic increase in rates between general rate cases to compensate for effects of inflation; and the ERAM procedure, which protects the utility from the possibility of the loss of fixed cost recovery due to fluctuations in electric sales levels.

These are also a number of indications of financial improvement for SDG&E, foremost of which are the recent upgrades of SDG&E's bonds and preferred stocks by the major rating agencies. We note that SDG&E was recently able to sell common stock above book value, which indicates that it is at or very close to earning its true cost of capital as determined by the market.

We do not have a precise method of quantifying and incorporating all of the above considerations into a specific rate of return on equity. However, in this case we do believe that a reasonable return lies within, and not at the extremes of the 15.6%-16.5% range. The high end of the range is inconsistent with the evidence in this case that SDG&E can meet its cost of equity requirements with a reduction in its current aurhorized rate of return on equity. This proposition is supported by improvements in the utility's financial position, and by improvements in the condition of the utility industry as a whole. We have carefully considered the level of these risks, along with the ratemaking devises which have been created to minimize negative financial impacts of uncertainty upon the utility.

At the same time, however, we find that interest rate volatility and uncertainty concerning the level of inflation is ongoing, perhaps increasing risk to SDG&E investors and to the utility industry as a whole. This is evidenced by our adoption of a 13% cost of debt rather than some of the more sanguine predictions made earlier this year.

In our judgement, based on the evidence before us and all the factors considered, we conclude that a rate of return of 16% is a reasonable estimate of SDG&E's cost of equity capital in the test year.

14.4 Adopted Rate of Return

After weighing the evidence in this proceeding, we are of the opinion that a rate of return on rate base of 12.82% for 1984 and 12.93% for attrition year 1985, providing a 16% return on common equity is reasonable and will enable PG&E to attract the necessary capital to provide reasonable service at reasonable rates to its customers.

The following table sets forth the adopted rate of return for 1984 and 1985, which assumes that all new long-term debt will sell at an interest cost of 13.0%.

Adopted Rate of Return

Test Year 1984

Component	Capitalization Ratio	Cost Rate	Weighted Cost
Long-Term Debt	45.50%	10.50%	4.78%
Preferred Stock	11.50%	10.08%	1.16%
Common Equity	43.00%	16.00%	6.88%
	100.00%		12.82%

Attrition Year 1985

Component	Capitalization Ratio	Cost Rate	Weighted Cost
Long-Term Debt	45.50%	10.75%	4.89%
Preferred Stock	11.50%	10.09%	1.16%
Common Equity	43.00%	16.00%	6.88%
			12.93%

14.5 Interest Rate Balancing Account

SDG&E proposed the implementation of an interest rate balancing account as an experiment for 1984 and 1985 in order to automatically capture the volatility of interest rates. It claims the beauty of balancing account is that it will capture the financial and operational realities of interest rate fluctuations for the benefit of both consumers and the company. SDG&E claims it is willing to forego the opportunity for any unanticipated benefits coming out of the current ratemaking process in exchange for protection against variations in interest rates which threaten the company's financial integrity. SDG&E claims this would be a two-way account benefiting the company and the ratepayers.

Witness Quan for the staff acknowledged that although SDG&E's proposal would operate for both the customers and the shareholders' benefit, he basically objected to the mechanism because it guarantees recovery of SDG&E's interest costs. The staff primarily opposes the balancing account idea because, in their view, it would reduce the incentive for the company to finance at the lowest cost and shelter it from all risks associated with changes in the general level of interest rates. When coupled with all the other balancing accounts which are in effect the proposal would be one more step in guaranteeing company profits during the test year.

We agree with the staff position. We are not convinced that the implementation of an interest rate balancing account is necessary or desireable at this time. As has been the case in most recent general rate case proceedings, the Commission allows for financial attrition by adopting a uniform capital structure for the test year and the attrition year, and allowing for varying projections of debt and preferred stock costs over the two years to reflect projected changes in the embedded cost of capital. This is a reasonable means by which to recognize the impact of financial attrition in 1985. Accordingly, we will continue to use this procedure to mitigate the impact of financial attrition on SDG&E.

Based on the adopted cost of long-term debt and preferred stock, the adopted allowance for financial attrition is set forth below:

Adopted Allowance for Financial Attrition
Attrition Year - 1985

	1984	1985	Difference
Long-Term Debt	4.78	4.89	.11%
Preferred Stock	1.16	1.16	
Common Equity	6.88	6.88	
			.11%

15. Conservation

Conservation, Load Management, and Cogeneration consumed more hearing time than any other issue in this proceeding, 15 days of the total of 65, or 23%! The positions on conservation of the several parties involved ranged from recommendations to do much more than in the past to a severe cutback of as much as 50% or more. Table 9 is a summary of the company and staff recommendations, the only parties to make presentations on all conservation subjects.

15.1 Conservation Policy

15.1.1 SDG&E's Policy

Although SDG&E requests $29.7 million for conservation, load management, and cogeneration, it only provides that figure as the estimated amount necessary to continue programs which satisfy existing governmental mandates, Commission programs ordered in past decision, and what SDG&E views as conservation services needed by its customers. SDG&E believes the amount shown as its alternate on Table 9 of $16,388,500 is the proper amount to spend. It believes programs which are not economically justified, that is, not cost-effective to its ratepayers or would cause rates to be higher than they would otherwise be in the long run, should not be continued. SDG&E claims utility-sponsored programs are not the major reason customers conserve, rather it is the high level of SDG&E's rates. SDG&E supports the $16.4 million estimate as the amount necessary to recover the ongoing expenses of prior years' program commitments, provide for customer service related conservation activities, and conduct cost-effective load management and voltage regulation.

Table 9

Expenses
Conservation - Cogeneration - Load Management

	Proposed 1984		
	SDG&E	Staff	SDG&E Alternate
Conservation			
Residential			
Weatherization	$ 5,191,300	$ 4,355,400	$ 474,100
Audits	4,033,400	2,951,700	1,800,000
Education	798,300	2,080,000	686,800
Subtotal	$10,023,000	$ 9,387,100	$ 2,960,900
Commercial/Industrial	6,210,000	6,210,000	1,773,900
Solar	4,431,500	4,062,400	3,975,600
Voltage Reg.	57,600	57,600	57,600
Ancillary	2,876,400	2,876,400	1,201,400
Subtotal	$23,598,500	$22,593,500	$ 9,969,400
Cogeneration	225,300	225,300	225,300
Load Management	5,876,300	2,926,000	6,193,600
Total 1984*	$29,700,100	$25,744,800	$16,388,500
Total 1985	$32,300,000		

Historical

1983	$26,500,000)	Estimated excluding solar
1982	$17,400,000)	
1981	$11,300,000	
1980	$ 7,000,000	
1979	$ 4,200,000	
1978	$ 2,600,000	
1977	$ 2,000,000	

*The three totals shown were revised late in the proceeding. However, the record does not contain enough information to show the detail for the revised total. For information the new totals are:

SDG&E	Staff	SDG&E Alternate
$27,647,900	$22,558,000	$15,927,100

15.1.2 Staff's Policy

Staff called as its policy witness George Amaroli, chief of the Commission's Energy Conservation Branch. Amaroli's appearance was in response to a request of the City of San Diego. San Diego made the request because the Commission's Utilities Division director had made a presentation on conservation program funding policy in the current PG&E general rate case. The presentation in the PG&E hearings recommended a "stay the course" position which is the position Amaroli adopted in this proceeding. His and staff witness Danforth's specific recommendations are contained in Appendix D. The staff's "stay the course" position means that SDG&E's conservation programs should be maintained in place at approximately the same funding levels as for 1983.

15.1.3 San Diego's Policy

San Diego, as many other parties do, wants any unspent funds from conservation programs in past years to be returned to the ratepayers. The staff is proposing certain penalties be assessed against the company for poor performance which will be discussed later. San Diego opposes these, in particular the one for load management. San Diego is concerned about whether the staff should even be allowed to recommend monetary penalties and recommends that the Commission conduct an investigation into the practice.

San Diego would like to see the load management activities cut back to the level recommended by the staff and, in addition, consideration be given to entirely eliminating the residential peakshift water heater program.

San Diego favors conservation and agrees with the staff recommendation to stay the course but views the "course" as some middle ground between the company and staff recommendations. For instance, San Diego believes the Commission should consider phasing out all programs that require large incentive payments to the participants such as the 8% residential weatherization program and the multifamily weatherization program. If these are cost effective to the participants then they should weatherize without ratepayer-funded incentives. In particular, San Diego sees such programs in the commercial/industrial area as prime candidates for discontinuance because it doesn't make sense to San Diego to force low-income residential customers to subsidize businesses, particularly in view of favorable tax credits and depreciation writeoffs. Also, the new programs proposed by the staff which cannot be shown to be cost-effective should not be started.

15.1.4 WRO's Policy

WRO supports the staff's stay-the-course ~~position.~~ Of particular importance to WRO is low-income weatherization and making conservation education materials more accessible to low-income ratepayers. WRO urges rejection of many of the staff's proposals such as residential time-of-use schedules, programs for refrigerator and water heater replacement, and expensive rebate programs.

WRO believes the company's use of the nonparticipant test as the sole basis for retention or rejection of conservation programs does not recognize the basic purpose of conservation which is to save energy, thereby reducing customer bills rather than just rates. WRO wants to see programs that allow the low-income customer to participate. WRO points to the direct weatherization program as one that benefits low-income groups. However, that program would be cut if the nonparticipant test is used to determine cost-effectiveness.

15.1.5 California Energy Commission's Policy

The California Energy Commission cites the law that requires it to adopt load management standards and requires this Commission to simply provide for the recovery of any expense caused a utility to comply with those standards. (See Public Resources Code Section 25403.5.) CEC further claims that, as required by law, it has implemented and carried out procedures for SDG&E which assure that the standards are technologically feasible and cost-effective compared with the costs for new electrical capacity. CEC has issued an order (CEC Order No. 83-0601-2 dated June 15, 1983 as revised by Order No. 83-0727-2 dated July 27, 1983) requiring SDG&E to implement certain peakshift load management programs. CEC claims staff's recommended funding levels will not cover the expected costs of the CEC mandated programs and recommends this Commission reject staff's proposal and adopt a policy of adequately funding CEC ordered programs.

15.1.6 SCRUB's Policy

The Schools Committee for Reducing Utility Bills requests that the Commission establish an on-going School-Utility Task Force to explore various energy efficiency measures and rate design possibilities for schools. SCRUB claims that most school districts in California have exhausted the low-cost and no-cost changes available to them to reduce energy costs and it is time to look at new approaches and try out new ideas for reducing school energy costs. SCRUB believes its task force idea is needed to explore and expand energy options available to schools. As one example, SCRUB suggests the possibility that utilities working with school districts could affect the consumption of energy in student's homes by using the established communication avenues between homes and schools. SCRUB concedes that it could establish such a committee, but if the Commission were to order it, it would be more effective because of the regulatory power of the Commission over the utilities and its ability to bring utilities throughout the state together for a common purpose.

As a general policy SCRUB believes the conservation programs offered schools by SDG&E have been valuable and should be continued at least at their existing levels.

15.1.7 Insulation Contractor's Association Policy

ICA urges the Commission to require full funding of the low-cost financing and multifamily weatherization programs which SDG&E has conducted over the last two years. Policies related to such programs should be maintained for at least the 1984 and 1985 rate years.

15.1.8 Sierra Club's Policy

Sierra Club believes SDG&E's conservation programs are working and should be continued. Sierra Club regrets what appears to it to be occasional antagonism between the company and the staff and would like to see a reconciliation and a spirit of problem solving advanced. It would like the Commission to bring this about by sending a firm signal that conservation programs are productive and desirable and should be continued at a viable level which optimizes the participation for all consumers. Sierra Club would like to see an investigation by the Commission of the possible mechanisms currently not available to SDG&E or authorized by the Commission which would improve the marketing techniques of SDG&E and provide incentives to promote expanded conservation activities.

15.1.9 Neuner's Policy

Edward J. Neuner, an SDG&E ratepayer appearing for himself, participated extensively in the hearings through cross-examination of witnesses on conservation issues. Through his participation, which included filing a brief, Neuner raises some important policy issues which we believe require careful consideration. Also, in accordance with his policy recommendations, Neuner recommends the lowest conservation expense level of all participants, $14,150,000 for 1984

Neuner believes the true problem of conservation is to find the point at which a reduction in usage would result in harm and not benefit. Thus, conservation must be treated as an exercise in economic choice, a balancing among the costs and benefits of alternatives. Of course, the most powerful force pressuring consumers to conserve is the cost of the commodity. Neuner contends that the importance of price-induced conservation is clearly evident in the effect which rising utility rates have had on reducing the growth of consumption.

If the marketplace is instrumental in bringing about conservation, Neuner wonders why there is a need for regulatory agencies to intervene in the process. He answers that perhaps it is to be sure consumers are informed of the choices and the alternative costs of such choices. Also, there is the need to keep conservation in the forefront so consumers do not become complacent and react only to major stimuli such as the OPEC-inspired oil price rises of the early 70's.

According to Neuner, attempts to mandate conservation based upon a purportedly "expert" judgment of how much ratepayers should "conserve" is a use of administrative authority not in accord with the long-standing function of utility regulation. He believes administrative efforts to define desirable conservation behavior are, at the least, likely to be presumptuous, if not ineffectual. He cites, for example, the staff's proposed "one warm room" program. Neuner does not believe consmers can be seriously expected to accept such an imposition upon their lifestyles and suggests the old New England practice of "bundling" as an alternative.

Neuner believes it is a simple fact that a limited number of participant beneficiaries of SDG&E's conservation programs are receiving their benefits at the expense of the larger group of non-participating ratepayers, and this raises fundamental questions of equity and discrimination in the regulation of SDG&E. He sees the starting-point for a regulatory conservation policy as an objective measure of cost-effectiveness which is equitable to all ratepayers. He maintains the non-participant test, such as that employed by SDG&E and the staff, and which we discuss later, can perform that function. Also, it is the only economically valid test which meets the regulatory standard of fair and reasonable rates. However, Neuner is aware that when a utility's marginal costs are less than its average costs the non-participant test will not show conservation measures to be cost-effective; he proposes that carefully considered programs should still be undertaken, particularly those of an informational nature.

In conclusion, Neuner recommends the program shown on Table 10.

Table 10

Neuner's Recommended Conservation, Load Management and Cogeneration Budget

Prior Year Commitments (SDG&E, Exh. #94)	$ 4,450,000
Cost-Effective Programs:	
Load Management (Staff, Exh. #102)	3,956,000
Conservation Voltage Regulation (SDG&E & Staff)	58,000
Ancillary Activities (SDG&E & Staff)	1,201,000
	$ 5,215,000
Information-Oriented Customer Service Programs (SDG&E, Exh. #94)	4,486,000
	$14,151,000

15.1.10 <u>Adopted Conservation Policy</u>

We are persuaded that present circumstances require us to make a close examination of SDG&E's conservation programs.

Several facts - that SDG&E's marginal costs are currently well below its average rate, that SDG&E is unlikely to face a capacity shortage in the next two years, that SDG&E's high rates already provide a substantial incentive for customer conservation - lead us to the conclusion that a less aggressive approach to conservation is now appropriate. At the same time, however, we are well aware that the energy situation may change dramatically and quickly. We are therefore reluctant to dismantle existing programs that may be highly beneficial in the future. The current circumstances thus present us with difficult choices. We reaffirm, however, that conservation is a preferred strategy for SDG&E; at the same time we recognize that the urgency of pursuing conservation may be less than in earlier years.

In addition to the general question of whether conservation programs produce fair and reasonable rates, our policy on conservation, load management, and cogeneration for SDG&E will be as follows:

1. Maintain and implement those programs which are required by law or governmental mandate.
2. Continue those programs required by past Commission decisions but review them to determine if they should be continued.
3. Maintain and implement those programs which provide conservation services needed by customers.
4. Implement only those new programs which are clearly shown to be cost-effective and, in particular, will avoid the need for additional future system generation capacity.
5. Phase out present and reject proposed programs which require incentive payments to participants borne by all ratepayers, including nonparticipants, but which are only cost-effective to the participants.

6. Phase out present and reject proposed programs which, because of the potential for reduced billings, would probably be undertaken by participants without incentive payments.

7. ~~Maintain or initiate programs which, although~~ they may not meet some of the above objectives, are worthwhile based on considerations of equity such as the ability of low-income groups to participate, externalities, and irreducible factors not ~~subject to precise economic measurement.~~

We will expect SDG&E and our staff to work closely during 1984 to effect the policy we have outlined above. Any problems with the program should be brought to our attention immediately through the advice letter filing procedure for our review and resolution.

15.1.11 Staff's Proposed Penalty Mechanism

We believe that a policy on penalties for nonperformance in the conservation area should be more carefully developed, particularly the provisions for rewards as well as penalties. The staff may wish to propose something in the 1986 rate case which can be considered by the Commission and the parties.

15.2 <u>Conservation Measurement and Cost-Effectiveness</u>

Most of the cost effectiveness analyses made for this proceeding are based on the recently issued joint report of our staff and the CEC staff entitled <u>Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs</u> by Danforth, Weiss, and Woychik. Although SDG&E did not base its tests strictly on the procedures outlined in the Standard Practice because it was not completed when it made its tests, it used procedures which were essentially similar to the staff's.

SDG&E used three tests to assess the cost-effectiveness of its conservation and load management programs: the participant test, the nonparticipant test, and the societal test. The participant test measures the costs and benefits of a program to ratepayers who use that program. The nonparticipant test measures the effect of a program on ratepayers who do not use the program but who do fund it. And the societal test measures the benefits of a program to society as a whole compared to the total cost to the utility of conducting the program.

Staff used the same three tests as SDG&E plus an additional test, the utility revenue requirement test. That test measures the effect of a program on the overall revenue requirement of the utility.

One of the factors in the formula for calculating the benefit/cost ratio in the nonparticipant test requires subtraction of the system average cost from the marginal cost. Normally this would indicate how much would be saved by eliminating a unit of power and not having to replace it at the marginal cost of energy. However, at this time SDG&E's

average cost exceeds its marginal cost by a significant amount. Both SDG&E and the staff expect that phenomenon to continue well beyond the year 2000. Therefore, all programs failed the nonparticipant test automatically.

To sum up the results of all four cost-effectiveness tests, all programs passed the participant test, no programs passed the non-participant test; all programs except the 8% and multi-family weatherization program and the energy information center program passed the societal test; and all programs tested passed the utility revenue requirement test.

There is very little controversy between SDG&E and staff on how the conservation measurement and cost-effectiveness tests should be made nor what basic figures, such as marginal costs, should be used to make the calculations. The differences, from a technical standpoint, are insignificant. Differences that exist are a result of how the tests should be used. SDG&E believes that if a program fails the nonparticipant test, it would be dropped regardless of the results of other tests. Staff takes the position that, although the nonparticipant test should certainly be considered, the Commission should also consider the other three tests in making its decisions on the desirability of programs. We agree with staff, and will consider the results of all four tests, in conjunction with the policies we have outlined in this decision.

15.3 Residential Programs

15.3.1 Weatherization

There are three programs under residential weatherization, 8% financing, direct weatherization assistance, and the multi-family program.

For the 8% financing program, SDG&E recommends $2,785,200 to do 8,000 units and the staff recommends $1,234,200 to do 10,000 units, if the program is continued at its present level. The company recommends the program be deleted but that $474,100 be provided to continue support of the units already completed. There was a controversy, of course, on why the two estimates for continuation of the program were so far apart considering the number of units recommended for completion. The staff witness conceded that his estimate was tempered by his belief that SDG&E probably could not complete the units he recommends, so he cut his estimate for expenses accordingly. Because the 8% financing program does not pass the societal test or the nonparticipant test of cost-effectiveness, we are reluctant to follow SDG&E's recommendation. We will authorize $1,392,600 for 1984 and 1985. At the per unit cost of SDG&E's request, that amount should allow completion and support of at least an additional 4,000 units in each year, which we set as the company goal for this program.

For the direct weatherization assistance (DWA) program SDG&E recommends 2,000 units for 1984 at a cost of $1,795,800 and the staff 4,000 for $2,000,000. Staff's lower cost per unit and larger number of units stems from its contention that there will be no start-up costs in 1984 and there are still over 12,000 units to be completed, therefore, 4,000 would be a reasonable goal. SDG&E disputes staff's estimates claiming that it is getting more costly to reach the low-income ratepayer because they are harder to sell even though the program is free, and there may not be any more than 8,000 units left to do. We believe this program needs a careful analysis using the policy criteria we have set up. We will authorize the company $1,800,000 and set the goal at 4,000 units for 1984 and 1985.

Staff witnesses recommend that financing guidelines for single- and multifamily installations should be consistent within the state. The specific recommendations of the staff are contained at pages 6-12 and 6-13 of Exhibit 100. They appear reasonable and should be adopted. In addition to a maximum rebate of 60¢ per square foot for installations involving flat roofs on multifamily housing, the following ceiling insulation financing limits in cents per square foot should be adopted.

Thermal Resistance Level	Cellulose	Other Approved Insulation Material
R-11	40	44
R-19	48	52
R-30*	59	63
R-38*	67	71

*Where determined to be cost-effective under RCS guidelines.

The multifamily weatherization program adopted by our D.93892 generated considerable controversy in this proceeding. Charges and countercharges flew about on whether landlords had been given free roofing jobs at ratepayers' expense, whether the staff had unnecessarily interfered in the administration of the program, and whether low-income ratepayers, who are most likely to be living in multifamily units, really got the benefits expected from lowered utility bills. Estimates by SDG&E and the staff for continuing the program reflect the controversy. SDG&E states it can do 500 units in 1984 for $610,300 and the staff claims the company should do 10,000 units for $1,121,200. Faced with discrepancies like that we almost throw up our hands, although the staff did admit that perhaps its estimates might be off by a margin of about three times. Like the DWA program, we are reluctant to see the multifamily program deleted entirely as SDG&E recommends. As with the DWA program we woule like to see a reevaluation based on our policy criteria; in the meantime we authorize the staff estimate of $1,121,200. According to SDG&E's estimates, that amount should allow weatherization of over 900 units. Assuming the staff's estimate has some validity, that amount should do considerably more than 2000 units. We ask the staff and company to confer on this and come to a mutually agreeable number for 1984 and 1985 which can be approved as the goal for 1984 through our advice letter procedure.

15.3.2 Residential Audits

There are two programs involving audits, the residential conservation service (RCS) and swimming pools. Taking pools first, we will not fund the program in 1984. Pools are usually a luxury owned by the more affluent ratepayers; we expect the inverted block rate design to provide those customers with an incentive to conserve.

SDG&E estimates it can carry out the required RCS audits for $1,800,000 which is below the staff estimate and will be adopted.

15.3.3 Education

Three programs in this category are not significantly disputed by SDG&E and the staff, and consist of brochures, information centers, and consumer counseling. The company proposes a minor change in emphasis for these programs. The authorized expenses will be $400,000 for brochures and $131,600 for consumer counseling.

In D.82-12-055, we instructed Southern California Edison Company to discontinue a program resembling SDG&E's information center program because of our concerns about the effectiveness of these information centers in actually effecting conservation. These concerns extend to SDG&E's program. We decline to authorize the expenditure of ratepayers' funds to support these centers.

For the meter conversion program which converts master meter gas and electric meters to individual meters in multifamily units, the staff recommends taking $382,000 from the RCS program to significantly accelerate the program in conjunction with audits. The idea would be to make the end-user aware of usage and therefore more likely to conserve. A $50 per meter rebate would be given to the landlord as an incentive to convert. The total cost of the staff program would be $461,000. SDG&E recommends the program be discontinued, but, if it is continued, 2,900 ~~units be done at a cost~~ of $79,000. We will fund the company proposal for 1984 and adopt the company's proposed goals but the program should be continued at the same level in 1985.

Both SDG&E and the staff recommend $15,000 for the pilot light reminder program, if it is continued. The company recommends the program be discontinued, however. This is a program which obviously meets our seventh criterion (Section 15.1.10) and should be continued.

SDG&E and staff both recommend $129,000 for the peak reduction program. The company further recommends, however, that it be discontinued. Although we have become increasingly sceptical of conservation programs based on advertising, we believe that it is important to continue to alert customers to the costs which peak-period consumption create for the utility system. We will authorize $100,000 for this program.

Staff recommends four new programs in addition to the accelerated meter conversion. "Pull the plug" would be directed at homes which are not continuously occupied. Owners would be urged to turn off all power not necessary during absences. "One warm room" involves turning off central heating and using portable heaters to warm only the room or rooms being used. The "refrigerator replacement" program would offer rebates to ratepayers who replace their refrigerators with more efficient units. And a "water heater replacement" program which would be similar to the refrigerator program. None of these were shown by the staff in the evidentiary record to be cost-effective and they will not be adopted. The refrigerator and water heater programs are particularly good examples of programs that would be difficult to participate in by low-income ratepayers.

15.4 Commercial/Industrial

The major programs under this category are non-residential audits and conservation assistance. Both SDG&E and staff recommend total expenditures including cogeneration for commercial/industrial of $6,435,300 although again, the company recommends severe reductions in the program down to a figure of under $2,000,000. The major part of the $2,000,000 would be $1,639,200 for mandated audits. We believe that audits provide commercial and industrial customers with important information on how to increase the efficiency of their energy use, and we will authorize $2,000,000 for audits. On the other hand, the high electricity rates should provide sufficient incentives for businesses to make use of that information and to take cost-effective steps to reduce energy consumption. Further financial incentives are not necessary, and we do not authorize funds for the conservation assistance program.

SDG&E requested $173,000 for its new business contact. Although we hope that all architects and engineers incorporate energy efficiency in their designs, we recognize that the utility can still play a valuable role. The planning of a building is also an ideal time to take steps to conserve energy. We will continue our 1982 authorization of $95,000 for this program.

We also adopt the company's recommendation of $79,000 for agricultural conservation, a substantial increase from the last rate case, and $56,700 for street light conversion.

15.5 Solar

There is little difference between staff and SDG&E on the cost of the solar rebate program. We will adopt the staff estimate of $3,891,100.

The solar energy project is designed to educate builders about solar energy techniques to employ in new construction. Many of the items included in this program are more effectively and more appropriately promoted by our vigorous solar energy industry. We will authorize items connected with the Pala Passive Solar Project and the Solar Storage Demonstration Program to increase the public benefits for SDG&E's research and development efforts. We will also allow a proportion of SDG&E's request for labor and miscellaneous, for a total authorization of $45,300.

15.6 Conservation Voltage Regulation

This is probably the one program everyone agrees is needed. SDG&E and staff agree on the cost, $57,600. It will be adopted.

15.7 Ancillary Expenses

Certain additional expenses are incurred by SDG&E for conservation activities which are not directly allocable to specific programs. These include general costs for buildings and services, advertising, management, and market research. Both SDG&E and staff recommend $2,876,400 for this expense, but under the reduced program recommended by SDG&E they would spend only $1,201,400. The record does not show how much of the reduction is due to an overhead reduction and how much to a direct reduction in activities such as market research. We will continue our 1982 authorization for building and services ($439,000) and for research ($764,000) and add a proportionate amount of the excess of SDG&E's request for a total authorization of $2,257,200.

15.8 Carryover and Supplemental Reserve

It appears that SDG&E will have at least $5 million of unexpended conservation and load management funds at the end of 1983. In D.93892 we stated "Any funds allowed in this decision for conservation, cogeneration, and load management which are unexpended at the end of the rate life of this decision will be subject to refund." We will accordingly order SDG&E to refund funds unspent as of December 31, 1983. By Resolution No. E-1979 we addressed the issue of load management and conservation underexpenditures carryover for PGandE. In Resolution No. E-1979 we found that:

"5. PG&E has agreed both in this filing as well in the current rate proceeding A.82-12-48 that by October 1, 1983, it will provide the Commission staff with an estimate of year-end 1983 Conservation and Load Management expenditures, to be comprised of two parts: (1) data on actual expenditures and encumbrances through the first 8 months of 1983, and (2) an estimate of expenditures and encumbrances for the remaining 4 months of 1983. Since October 1, 1983 is a Saturday, the next business day Monday, October 3, 1983 should be the submittal date. This information is to be presented by program as identified in A.82-12-48 and which is consistent with present accounting procedures.

"6. PG&E has agreed that 1982 and 1983 authorized, but unexpended or unencumbered Load Management and Conservation Funds, plus accrued interest, may be credited against 1984 Load Management and Conservation funding which will be established in PG&E's current rate proceeding (A.82-12-48). Interest will be based on one-half of each year's beginning plus end-of-year fund balance as recorded for year 1982 and estimated for year 1983, at the annual average short-term 90 days commercial paper interest rate, which for calendar year 1982 was 11.289%.

We will apply these guidelines to SDG&E's unspent 1982 and 1983 funds. We believe a reasonable estimate of those funds is $ 5.053 million, including interest. Interest is calculated based on one-half of each year's beginning plus end-of-year balance as recorded for 1982 and estimated for 1983. Consistent with Resolution No. E-1979, the full amount should be credited against the 1984 revenue requirement. For accounting purposes, it should be treated as a reduction in the revenue requirement associated with the conservation budget. SDG&E is expected to maintain the conservation budget authorized by this decision. We authorize a compensating 1985 attrition adjustment to the conservation budget.

A reevaluation of the above carryover figures will be needed once actual 1983 conservation and load management expenditures are determined. We order SDG&E to provide true-up calculations and supporting data to our staff, who will provide an independent analysis. Any amount by which the authorized credit differs from the true-up results will be carried forward, with interest, and will be reflected in the 1985 attrition adjustment.

Unspent funds in the future will be treated in the following manner, consistent with Resolution No. E-1979:

1. Conservation, Load Management, CVR, and 12-21kv conversion funds not spent in the test year will be carried forward with interest to the attrition year. The computation will be done once final test year expenditure levels are known.

2. Interest will be based on one-half the 1984 end-of-year balance, including encumbered but unspent funds, at the annual average short-term 90-day commercial paper rate.

3. Any carryover of unexpended funds during the attrition year will be accounted for in SDG&E's next general rate case in a manner to be decided therein.

We believe that it is appropriate to allow the company some flexibility in adjusting its conservation and load management program to meet changing circumstances. At the same time, we are reluctant to allow the company complete freedom to spend money earmarked for conservation in any way it sees fit.

We adopt as reasonable for the test year 1984 a supplemental reserve for conservation and load management of $2 million. We believe a supplementary reserve of this amount is reasonable particularly since we have retained existing goals for low-income weatherization programs. Expenditures authorized under the supplemental reserve will be spent only on the direct weatherization programs and SDG&E will be required to provide a full accounting of such amounts.

However, we stress that no supplemental reserve funds may be used unless prior approval has been received from staff for amounts up to $150,000. Such approval must be in writing and signed by the Executive Director. For amounts in excess of $150,000 in a single year, prior Commission approval must be obtained. This approval should be requested by an advice letter. Funds expended from the supplementary reserve without prior authorization will not be recovered in rates.

16. Cogeneration

Both SDG&E and staff recommend $225,300 for cogeneration activities which will be adopted.

16.1 Staff's Proposed Penalty

The only issue in the cogeneration budget area is staff's recommendation that SDG&E be penalized 30 basis points on its electric department rate of return, approximately $2.6 million, for activities staff claims have discouraged the development of alternative customer generation in SDG&E's service territory.

Staff bases its recommendation on four sub-issues, a comparison of SDG&E's efforts in the cogeneration field with that of PG&E, complaints about the company's cogeneration program, deliberate and unnecessary lowering of its payment rates to qualifying facilities (QFs), and unnecessary insurance requirements for QFs.

Comparing the efforts of SDG&E to PG&E the staff concluded that PG&E has acquired 2½ times more capacity than SDG&E and SDG&E has eight times more inactive projects than PG&E. Staff's calculations take into account the relative size of the two utilities. SDG&E countered the staff contention with evidence that the territories served by the two utilities are quite different. SDG&E does not have the industrial, oil refining, and large agricultural base that PG&E has. Also, there is less potential for the development of wind or hydro projects in SDG&E's territory.

SDG&E claims that the staff compared projects and megawatts inconsistently in its analysis and did not account for any differences in the reporting criteria used by the two utilities.

Staff's contention that it had received numerous complaints about SDG&E's cooperation on cogeneration was not supported by its witness.

Staff's claims that SDG&E badly mishandled payments and information given out regarding incremental heat rates is well founded. However, there is no hard evidence of a clear and convincing nature that SDG&E's actions were deliberate attempts to misinform the public or its QFs.

SDG&E had been demanding what appears to be unnecessary insurance requirements which could have dissuaded small installations from developing. In rebuttal testimony, an SDG&E witness stated that the company had recently dropped its insurance requirements for cogenerators under 10 kW, but agreed, under cross-examination, that the action was taken because other utilities had done the same and not necessarily because SDG&E felt it was the appropriate thing to do.

We cannot agree that the actions of the company have been to deliberately discourage cogeneration; the staff's recommended penalty is rejected.

16.2 <u>Applied Energy Incorporated Divestiture</u>

Applied Energy Incorporated (AEI), a wholly-owned subsidiary of SDG&E, was founded in 1968 to engage in the business of cogeneration. Because there is a potential for large growth in the cogeneration area, SDG&E has sought out investors that would buy up a majority of the AEI common stock owned by SDG&E so that there would be the required infusion of new capital in the immediate future for any expansion that AEI would require.

SDG&E will be required to file for Commission approval before any utility property can be transferred or sold to AEI or to any new corporation formed to proceed further in the cogeneration market. The staff recommends that if SDG&E divests itself of any stock interest in AEI, SDG&E should be required to formalize all written agreements between the two parties and that all fuel, operation, and maintenance credits be restricted to only costs and expenses of a direct nature. These credits have usually been immaterial from a ratemaking standpoint, but the staff feels they should be passed on to any succeeding corporation. Substantially all of the operating, maintenance, administrative, and general expenses of AEI are paid to SDG&E through billings to AEI by SDG&E. The billings are based on the actual time and expenses incurred by SDG&E employees who provide the nonutility services to AEI.

Because SDG&E will be required to file for Commission approval before any part of utility property can be transferred or sold to AEI, it will be sufficient that we address, at that time, the problems brought up by the staff.

17. Load Management

There are two issues requiring resolution in the load management area, staff's proposed penalty of $2,301,500 for what it claims to be SDG&E's failure to actively pursue its load management programs, and the level of air conditioner and water heater peak-shift installations.

17.1 Staff's Proposed Penalty

We will dispose of the penalty issue first, with the assistance of the City of San Diego's brief and statement at oral argument. The staff witness who recommends the penalty reported that in 1982 SDG&E spent only 61% of its authorized load management funds and proposes to spend only 51% in 1983. This amounts to a total of $7,227,315 or about 50% of the $14,361,000 authorized for 1982 and 1983 in the last general rate case.

D.93892 provides that funds allowed in that decision for conservation, cogeneration and load management, which are unexpended at the end of the rate life of the decision, are subject to refund. Therefore, staff recommends that this amount, plus interest, be refunded to the ratepayers.

Unfortunately, the same witness then uses this saving as the main basis for recommending that a net penalty of $2,301,500 be assessed against SDG&E for not actively pursuing load management objectives. To put this in the proper perspective it must be remembered that this is the same witness who is recommending a 50% reduction in SDG&E's proposed load management programs for 1984 and 1985 because there isn't really a need for a load management program at this time. At RT 7284-5 the following exchange took place:

> "Q Well, you're talking about these programs slowing down.
>
> "Aren't in fact these programs just starting up?
>
> "A These programs are starting up, but there is no evidence on the record that San Diego needs the load management in the lump sum the way that's [sic] going at a big effort.
>
> "And I think the available information indicates to me that it will be a few years before they're really needed by San Diego Gas & Electric Company.
>
> "And I think the programs should be curtailed slightly and possibly adjusted and adapted to find out really what will make them more acceptable to the customers of San Diego Gas & Electric Company.

"So, in essence, I would be recommending that they -- that, the programs be slowed down, modified slightly, until such time as the demand really is there for a load management program, and that they have a better developed program at that time.

"EXAMINATION

"BY ALJ PORTER:

"Q Mr. Allen, this seems to be a very important point.

"I wonder why you didn't address it in your exhibit.

"A It wasn't fully developed at the time that my exhibit was prepared, your Honor.

"Q Well, wasn't your exhibit prepared after you made these work papers or after making the calculations on the work papers?

"A The -- my report was prepared at the time that I -- based upon my available information and my inclination at the time was that the available information indicated that there was no real necessity or need for load management programs in San Diego Gas & Electric's service territory in the immediate future.

"It will be there in the long term.

"At this time, and my feeling at the time I prepared the report, and it's been reinforced since, is that they really should attempt to get the programs fully developed, operational and do some more research on how they can reduce their costs in the program."

We see no reason to assess a penalty on SDG&E for doing, in 1982 and 1983, what the staff is recommending be done in 1984 and 1985, namely, cutting back on load management expenses because there is no capacity problem foreseen in the next few years.

17.2 Level of Activities

As previously cited under Section 15.1.5 of this decision the CEC has issued an order which requires SDG&E to install up to 8,000 central air conditioner cutoff switches in each of the years 1984 and 1985. CEC also ordered SDG&E to continue its water heater cycling experiment and, if cost-effectiveness is demonstrated, expand the program to install up to 6,000 switches in each of the years 1984 and 1985. The operative words which have caused a dispute between our staff and the CEC representative in these proceedings are "up to." There seems no question that some liberties can be taken with the water heater switch requirement but the 8,000 air conditioner switches means at least 8,000, claims CEC, less any that might be recycled for installation in second locations. SDG&E interprets the 8,000 as a requirement, our staff does not. We think the simple way out is to authorize enough for the 8,000, subject to refund and if the funds are not used and if the company does not install 8,000 it is between it and CEC. Therefore, we will adopt the SDG&E recommended amount for air conditioners and the staff's for water heaters. We will also adopt SDG&E's request for the commercial peakshift program. The other expenses proposed by staff appear to be reasonable and, subject to the same refund conditions we put in the last rate case, will be adopted. The total load management budget authorized will be $4,722,600.

18. Adopted Budget for Conservation, Cogeneration, and Load Management

Based on the foregoing discussion, Table 11 is a summary of our adopted maximum budget for conservation, cogeneration, and load management. Except for the procedures we have adopted for the supplemental reserve, the present limitations and procedures for shifting funds between programs will continue in effect.

Table 11

Adopted Expenses
Conservation - Cogeneration - Load Management

Conservation	
Residential Weatherization	$ 4,115,700
Audits	1,729,400
Education	635,300
Subtotal	$ 6,480,400
Commercial/Industrial	1,951,600
Solar	3,902,700
Voltage Regulation	50,400
Ancillary	1,976,300
Subtotal	$ 14,361,400
Cogeneration	197,200
Load Management	4,277,400
Subtotal	$ 18,836,000
Supplemental Reserve	2,000,000
TOTAL	$ 20,836,000

19. Revenue Requirement and Adopted Results of Operations

Table 12 incorporates all of the foregoing discussion of revenues, expenses, rate base, and rate of return into our adopted results of operations for SDG&E's three departments. The results show that SDG&E will need additional revenues of $12,678,000 over those produced under present rates for test year 1984. The reader will note that the gross revenues are substantially below the revenues used for some of the discussions on revenue allocations. This is because Table 12 does not include ECAC or gas supply revenue and expense adjustment mechanisms.

SAN DIEGO G & E - ELECTRIC DEPARTMENT

SUMMARY OF EARNINGS

TEST YEAR 1984 AT PRESENT RATES

LN NO	ITEM	TOTAL SYSTEM	CPUC JURISDICTIONAL
1	OPERATING REVENUES		
2	REVENUES	528417.0	526665.0
3	TOTAL OPERATING REVENUES	528417.0	526665.0
4	OPERATING EXPENSES		
5	PRODUCTION	66678.8	66282.0
6	TRANSMISSION	18909.5	18658.0
7	DISTRIBUTION	30142.0	30142.0
8	CUSTOMER ACCOUNTS	12903.4	12903.0
9	CUST. SERVICE & INFORMATION	10422.7	10423.0
10	ADMINISTRATIVE & GENERAL	55443.0	55305.0
11	BLYTHE AMORTIZATION ($84)	8021.0	7978.0
12	SUBTOTAL	202520.4	201691.0
13	LABOR ADJ.	15146.1	15100.0
14	NON-LABOR ADJ.	5341.7	5324.0
15	UNSPENT FUNDS	-2693.0	-2693.0
16	SUBTOTAL AFTER WAGE ADJ.	220315.2	219422.0
17	DEPRECIATION & AMORTIZATION	66154.6	65968.0
18	TAXES OTHER THAN INCOME	18910.9	18852.0
19	CALIF CORP FRANCHISE TAX	16486.1	16441.0
20	FED CORP INCOME TAX	72800.8	72601.0
21	TOTAL OPERATING EXPENSES	394667.6	393284.0
22	NET OPERATING REVENUES ADJUSTD	133749.4	133381.0
23	RATE BASE	1083570.0	1077523.0
24	RATE OF RETURN	12.34	12.38

TABLE 12

SAN DIEGO G & E - ELECTRIC DEPARTMENT

ADOPTED

SUMMARY OF EARNINGS

TEST YEAR 1984 AT ADOPTED RATES

LN NO	ITEM	TOTAL SYSTEM	CPUC JURISDICTIONAL
	OPERATING REVENUES		
1	PRESENT RATE REVENUES	528417.0	526665.0
2	REVENUE INCREASE	10818.0	9965.0
3	TOTAL OPERATING REVENUES	539235.0	536630.0
4	OPERATING EXPENSES		
5	PRODUCTION	66678.8	66282.0
6	TRANSMISSION	18909.5	18658.0
7	DISTRIBUTION	30142.0	30142.0
8	CUSTOMER ACCOUNTS	12929.2	12927.0
9	CUST. SERVICE & INFORMATION	10422.7	10423.0
10	ADMINISTRATIVE & GENERAL	55656.2	55501.0
11	BLYTHE AMORTIZATION ($84)	8021.0	7978.0
12	SUBTOTAL	202759.4	201911.0
13	LABOR ADJ.	15146.1	15100.0
14	NON-LABOR ADJ.	5341.7	5324.0
15	UNSPENT FUNDS	-2693.0	-2693.0
16	SUBTOTAL AFTER WAGE ADJ.	220554.2	219642.0
17	DEPRECIATION & AMORTIZATION	66154.6	65968.0
18	TAXES OTHER THAN INCOME	18910.9	18852.0
19	CALIF CORP FRANCHISE TAX	17501.7	17377.0
20	FED CORP INCOME TAX	77199.9	76653.0
21	TOTAL OPERATING EXPENSES	400321.3	398492.0
22	NET OPERATING REVENUES ADJUSTD	138913.7	138138.0
23	RATE BASE	1083570.0	1077523.0
24	RATE OF RETURN	12.82	12.82

TABLE 12

SAN DIEGO G & E - GAS DEPARTMENT

ADOPTED

SUMMARY OF EARNINGS

TEST YEAR 1984 AT PRESENT RATES

LN NO	ITEM	
1	OPERATING REVENUES	
2	REVENUES	103428.0
3	TOTAL OPERATING REVENUES	[illegible]
4	OPERATING EXPENSES	
5	GAS SUPPLY	[illegible]728.[illegible]
6	GAS STORAGE	1813.8
7	TRANSMISSION	1998.4
8	DISTRIBUTION	11819.6
9	CUSTOMER ACCOUNTS	6935.5
10	CUST. SERVICE & INFORMATION	[illegible]
11	ADMINISTRATIVE & GENERAL	15709.[illegible]
13	SUBTOTAL	46746.4
14	LABOR ADJ.	4790.4
15	NON-LABOR ADJ.	1359.9
16	UNSPENT FUNDS	-2342.[illegible]
17	SUBTOTAL AFTER WAGE ADJ.	50554.2
18	DEPRECIATION & AMORTIZATION	13354.4
19	TAXES OTHER THAN INCOME	3409.3
20	CALIF FRANCHISE TAX	2900.[illegible]
21	FEED CORP INCOME TAX	11929.[illegible]
22	TOTAL OPERATING EXPENSES	82148.2
23	NET OPERATING REVENUES ADJUSTD	21279.8
24	RATE BASE	181619.[illegible]
25	RATE OF RETURN	11.72%

TABLE 12
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SAN DIEGO G & E - GAS DEPARTMENT
ADOPTED
SUMMARY OF EARNINGS

TEST YEAR 1984 AT ADOPTED RATES

LN NO	ITEM	
	OPERATING REVENUES	
1	PRESENT RATE REVENUES	103428.0
2	REVENUE INCREASE	4215.0
3	TOTAL OPERATING REVENUES	107643.0
4	OPERATING EXPENSES	
5	GAS SUPPLY	-728.1
6	GAS STORAGE	1813.8
7	TRANSMISSION	1998.4
8	DISTRIBUTION	11919.6
9	CUSTOMERS ACCOUNTS	6905.5
10	CUST. SERVICE & INFORMATION	9197.7
11	ADMINISTRATIVE & GENERAL	15859.8
13	SUBTOTAL	46856.7
14	LABOR ADJ.	4790.4
15	NON-LABOR ADJ.	1359.9
16	UNSPENT FUNDS	-2342.0
17	SUBTOTAL AFTER WAGE ADJ.	50665.0
18	DEPRECIATION & AMORTIZATION	13354.2
19	TAXES OTHER THAN INCOME	3409.5
20	CALIF FRANCHISE TAX	3294.6
21	FED CORP INCOME TAX	13636.2
22	TOTAL OPERATING EXPENSES	84359.5
23	NET OPERATING REVENUES ADJUSTD	23283.5
24	RATE BASE	181619.0
25	RATE OF RETURN	12.82

TABLE 12
Page 5 of 6

SDG&E
Steam Department
Adopted Results of Operations
At Present Rates
($1000)

TOTAL OPERATING REVENUES	$ 282
OPERATING EXPENSES	
TOTAL PRODUCTION EXPENSES	$ 69
DISTRIBUTION EXPENSES	82
CUSTOMER ACCOUNT	2
ADMIN. & GENERAL EXPENSES	62
SUBTOTAL	$ 215
WAGE ADJ.	$ 32
NON-LABOR ADJ.	1[illegible]
SUBTOTAL AFTER WAGE ADJ.	$ 261
DEPRECIATION	$ 40
TAXES OTHER THAN INCOME	16
CALIF FRANCHISE TAX	0
FED CORP INCOME TAX	-22
TOTAL OPERATING EXPENSES	$ 295
NET OPERATING REVENUES ADJUSTD	$ -13
RATE BASE	$ 434
RATE OF RETURN	-2.99%

TABLE 12
Page 6 of 6

SDG&E
Steam Department
At Authorized Rates
($1000)

TOTAL OPERATING REVENUES	$417
OPERATING EXPENSES	
TOTAL PRODUCTION EXPENSES	$ 69
DISTRIBUTION EXPENSES	82
CUSTOMER ACCOUNT	2
ADMIN. & GENERAL EXPENSES	65
SUBTOTAL	$218
WAGE ADJ.	$ 32
NON-LABOR ADJ.	14
SUBTOTAL AFTER WAGE ADJ.	$264
DEPRECIATION	$ 40
TAXES OTHER THAN INCOME	16
CALIF FRANCHISE TAX	7
FED CORP INCOME TAX	35
TOTAL OPERATING EXPENSES	$362
NET OPERATING REVENUES ADJUSTD	$ 55
RATE BASE	$434
RATE OF RETURN	12.82%

20. Marginal Costs

Under policy guidelines adopted by this Commission, marginal costs are used for several purposes in general rate proceedings. They are used for allocation of revenues to the various customer classes, to determine the cost-effectiveness of conservation programs, and to set payments to cogenerators. Marginal cost is generally that increment of cost necessary to produce one more production unit such as a kilowatt-hour. There are three types of marginal costs to be considered, energy, demand, and customer. The customer cost component is not used by the Commission for rate design and revenue allocation purposes because it is not affected by small variations in system load. A witness for FEA recommended that it be included because the load increments for which marginal demand and energy are determined are primarily due to the addition of new customers to the system.

20.1 Electric Service

SDG&E and the staff presented two different electric service marginal cost determinations but which produced similar results. We will adopt the staff method because it reflects our D.82-12-055 in the 1983 general rate case of Southern California Edison Co., A.61138. The method adopted in that decision does not use the customer component, therefore, we will reject FEA's recommendation for the sake of maintaining statewide uniformity.

20.2 Gas Service

The primary difference in SDG&E's and staff's method for gas marginal costs was SDG&E's use of SoCal Gas' system average cost, whereas staff used SoCal's marginal and average costs as proxies for SDG&E. SDG&E claimed its method was a simpler approach that eliminated the need to analyze SoCal's gas planning activities. However, SDG&E's method does not take into account the inextricable relationship between SoCal and SDG&E which causes changes in SoCal's operations and costs depending on the needs of SDG&E's customers. For instance, SoCal cannot serve its low priority customers if SDG&E's high priority customers have not been served. Staff claims that, for practical purposes, customer requirements of the two systems are merged. We will adopt the staff presentation.

21. Electric Revenue Allocation

There were four more or less specific proposals for allocating revenues among the various classes of customers. SDG&E, staff, SCRUB, and FEA made proposals and others, such as San Diego and WRO brought out certain alternatives through their participation.

21.1 SDG&E's Proposal

SDG&E proposes to allocate the total revenue requirement among the classes of service by the following three steps:

Step 1: Increase the lighting schedules based on the percent increase in total rates.

Step 2: Calculate the revenue allocation to the other schedules using the full marginal energy and demand rates.

Step 3: Adjust the revenues produced in Step 2 on an equal cents per kilowatt-hour basis for all nonlighting schedules to yield the proposed revenue requirement.

It will be noted that, because of the uniform cents per kilowatt-hour adjustment in Step 3, the revenue allocation will not be proportional to marginal cost. SDG&E argues that this is appropriate because it preserves the absolute differences in cents per kilowatt-hour between classes produced by the marginal cost allocation.

21.2 Staff's Proposal

Staff also proposes a three-step method to allocate the revenue requirement among the classes of service with some alternatives for the third step:

Step 1: Increase lighting schedules by the system average percentage increase.

Step 2: Develop an average short-run marginal demand and energy cost in cents per kilowatt-hour by class of service.

Step 3: Ratio present rates by class upward by the weighted average of marginal cost relationships and the system percent increase to recover revenue required under adopted results of operations.

Step 3, the Weighted Average allocation method, is offered by the staff to replace the Equal Percentage of the Difference Method (EPD) which was used by the Commission for allocating base revenue increases in SDG&E's last general rate case. The staff's new method, unlike the EPD, is intended to provide progress toward marginal cost-based class revenue allocations under all circumstances. The EPD method does not move toward marginal cost-based allocations when total system marginal cost revenue is less than total system present revenue, as in the current case for SDG&E. This situation did not arise when only base revenues were considered in general rate case revenue allocations. However, now that we are applying marginal costs to total revenues (base + fuel and other offsets), the operational limitations of the EPD method show up. For example, Table 13 illustrates the results of the EPD method applied in a simplified case where system marginal cost revenues are less than actual system revenues. Let us examine what happens to the proportional relationship between Class A and Class C rates. Class

A's rate starts out at 40% of Class C's rate (2/5 = 40%). In a strict marginal cost-proportional structure, A's rate should be 33% of C's (1/3=33%). However, after applying the EPD allocation, A's rate becomes 40.9% of C's ($\frac{2.25}{5.50}$ = 40.9%). In short, EPD has resulted in moving further away, rather than closer to the marginal cost based structure. Indeed, it can be shown that the EPD method will produce contrary results whenever the EPD factor (-1/4 in the Table 13 example) is either negative or greater than 1.0.

Table 13

The Equal Percentage of the Difference
(EPD) Allocation Method

Class	Usage	Present Average Rate & Revenue*	Marginal Cost Rate & Revenue**	EPD Target Average Rate and Revenue
A	1	2	1	2.25
B		3	2	3.25
C		5	3	5.50
Total		10	6	11.00

EPD Formula to Produce Target Revenue:

$$\text{Class Target Revenue} = \left[\text{Class Marginal Revenue} - \text{Class Present Revenue}\right] \times \left[\frac{\text{System Target Revenue} - \text{System Present Revenue}}{\text{System Marginal Cost Rev.} - \text{System Present Revenue}}\right] + \text{Class Present Revenue}$$

Example:

$$\text{Class A Target Revenue} = [\,1 - 2\,] \times \left[\frac{11 - 10}{6 - 10}\right] + 2 = 2.25$$

NOTE: In this case the equal percentage of the difference factor is - 1/4. In any case the EPD factor is the same for all classes.

* For SDG&E, average costs exceed marginal costs.

** Because the usage for each class is set at 1 in this example, the rate for each class equals its revenue and the total of the rates equals the total revenue.

Although the Commission policy is to allocate revenues based on marginal costs, that policy has been applied to base revenues only while fuel cost revenues have been distributed on an equal cents per kilowatt-hour basis. Base revenues are all revenues necessary to support the electric department operation except the cost of fuel. The revenues required to pay for fuel are handled in a special balancing account. That account is generally reviewed for reasonableness twice a year through a mechanism called the Energy Cost Adjustment Clause (ECAC). Therefore, tariff rates contain "base rates" and "ECAC rates." In D.82-12-113 dated December 22, 1982 in A.60153 and A.60616 of PG&E relative to 1983 attrition and ECAC rates, the Commission indicated it wanted the ECAC portion of rates allocated on marginal costs; but it recognized that the equal percentage of the difference method does not work when applied to decreases. Because these are balancing accounts there are decreases as well as increases. Consequently, the Commission directed the staff to develop a modification to the EPD method that would work for base and ECAC rate changes that result in increases or decreases.

Other than the EPD method and the equal cents per kilowatt-hour add-on, there are two quite obvious ways to allocate a change in revenue requirement whether it is a decrease or an increase. The first is to simply take the present revenue for a given class and change it by the percentage change in the total system revenues, call it the system percentage change method. The second is to take the marginal cost of each class divided by the marginal cost for the system and multiply the resulting percentage times the system revenue requirement, call it the marginal cost method. The first would preserve present interclass relationships and the second would provide rates based completely on marginal costs.

The staff proposes a combination of the system percentage change and the marginal cost methods. Depending on how quickly the

Commission wants to achieve full marginal cost-based rates it can adjust the weight it gives to each method. Staff proposes as a start to use a 50/50 weighting for this proceeding. However, it does not oppose going to the full marginal cost-based method of spreading revenue requirement, a proposal of FEA we will discuss later.

Table 14 takes the basic assumptions of Table 13 and illustrates how the methods proposed by SDG&E and staff would be applied, as well as the marginal cost allocation. For convenience and clarity, the proposal of SDG&E and staff to first increase the lighting classes by the system percentage increase is ignored. Tables 13 and 14 are for illustrative purposes and should not be used to compare results reached by the various methods.

Table 14

SDG&E, Staff, and Marginal Cost Allocation Methods

Class	Usage	Present Average Rate & Revenue	Marginal Costs and Rates	% of Marginal Cost	Target Revenues
A	1	2	1	16.7%	
B	1	3	2	33.3%	
C	1	5	3	50.0%	
Total Revenue		10	6	100.0%	11

SDG&E Method

The difference between marginal cost system revenue and target system revenue is 5.00. 5.00 divided by system usage = 1.67. Target revenue equals marginal cost revenue + 1.67.

Class	Marginal Cost Revenue	Equal Adjustment	Target Revenue
A	1	1.67	2.67
B	2	1.67	3.67
C	3	1.67	4.67
			11.00

Staff 50/50 Method

Allocation based on the system percentage change method and marginal cost method weighted 50/50.

Class	(A) Present Revenue	(B) (A) Times System Increase (11/10)	(C) Marginal Cost Pro Rata Allocation		(B) + (C) / 2
A	2	2.20	1.84	(16.7%)	2.02
B	3	3.30	3.66	(33.3%)	3.48
C	5	5.50	5.50	(50.0%)	5.50
		11.00	11.00	(100.0%)	11.00

Marginal Cost Method

Column (C) of the staff method shows the allocation on a marginal cost basis.

21.3 SCRUB's Proposal

The Schools Committee for Reducing Utility Bills made a revenue allocation proposal which it claims properly emphasizes marginal costs and, in particular, short-run marginal costs. SCRUB's method involves two major steps, a marginal cost allocation (Economic Allocation), and then an adjustment of that allocation to account for any policy considerations the Commission might wish to account for (Policy Adjustment).

SCRUB made similar presentations in both this proceeding and PG&E's current general rate case. Because SDG&E's marginal costs are less than its average costs and PG&E has the reverse situation, SCRUB's proposals were different for the two utilities, although the principles followed are consistent. SCRUB's first step for SDG&E consists of four substeps:

a. The total marginal cost of a given class of service is calculated.

b. The total marginal cost revenue of all classes is subtracted from the total system revenue requirement.

c. A factor is calculated which is the ratio of the short-run marginal cost of the class and the total short-run marginal cost of all classes.

d. The number in Step b is multiplied by the factor from step c and that number is added to the number in step a to obtain the revenue allocation for the class.

It follows that the method allocates part of the revenue requirement by total marginal costs and part by short-run marginal costs; SCRUB claims the emphasis is on short-run marginal costs. SCRUB deems this to be a better allocation method than relying on total marginal costs because it sends a more current signal to consumers of what it costs to serve them. SCRUB maintains its method responds to the Commission's request for a method that will work in any type of situation; whether there are decreases involved or marginal costs are less than average or vice versa makes no difference.[5] Also, the method satisfies the criterion set up in the Public Utilities Regulatory Policies Act of 1978 (PURPA) that rates should reflect cost of service to the extent practicable.

SCRUB calls its method PACMAC which stands for Policy Adjusted Class Marginal Cost. Which brings us to the second major step in the process, the policy adjustment step. SCRUB includes this so the Commission can adjust the straight marginal cost allocation results to reflect Commission policy considerations. Examples are the streetlighting and maximum increase caps suggested by some of the parties. By way of further illustration, SCRUB used the PACMAC method to calculate the revenue allocation under one of the target revenue proposals and it resulted in a considerable shift of revenue from the commercial/industrial class to the residential. Residential rates would be increased 29.10% and commercial/industrial decreased 2.36%. (We note schools are included in the commercial/industrial classes.) The ALJ requested SCRUB to make an allocation of present revenues using the PACMAC method and compare that to the current equal percentage of the difference method. That was done and filed as a statement of counsel. It shows that residential revenue would increase by 21%, commercial/industrial would decrease by 11%, and agricultural by 9%. The revenue shift out of a $1.233 billion revenue requirement for the three classes would be residential, plus $89 million, commercial/industrial, minus $87 million, and agricultural, minus $2 million, a significant shifting among classes.

5 The formula is applied differently if marginal costs exceed or equal average costs. See Exhibit 66 of witness Hairston.

21.4 Proposal of Federal Executive Agencies

FEA proposes that the revenue allocation be based on total marginal cost relationships. It would determine the ratio of total marginal cost to total revenue requirement and apply that to the marginal cost of each class of service. This results in a straight marginal cost revenue allocation. However, FEA would limit the percent increase for any class to twice the system average. FEA also recommends that its method be applied by individual rate schedules rather than rate schedule groups as proposed by SDG&E, staff, and SCRUB. As discussed previously at Section 20, FEA recommends including marginal customer costs in the marginal cost determination. FEA also recommends use of marginal costs by component and the costing periods proposed by the staff rather than those proposed by SDG&E.

21.5 Discussion and Adopted Allocation Procedure

Table 15 is a summary of how the various proposals before us would affect the revenue distribution if total revenue of $1,230,300,000 is required including base and ECAC revenues, and excluding retail and miscellaneous. It is pointed out that:

1. Certain calculations have been made to make the totals for some of the proposals, such as SCRUB's, come to the revenue requirement. These have been done on a ratio basis in an attempt to preserve relative values.

2. The staff's figures are based on its recommended 50% system average/50% marginal cost method although staff leaves the final ratio to the Commission, if it adopts the staff method.

Table 15

San Diego Gas & Electric Company

Comparison of Proposed Revenue Allocation Methods

Test Year 1984

(Revenue in $ 000's)

Class of Service	Present Effective Revenues	Proposed Rates Revenues SDG&E	Staff	SCRUB	FEA
	(1)	(2)	(3)	(4)	(5)
Residential	412483	402927	409054	485645	423011
Comm. & Inc.	769258	794608	788175	714095	779605
Agricultural	21274	20842	21159	18623	20686
Lighting	11765	11915	11915	11915	6980
Total :	1214750	1230282	1230293	1230278	1230282

Percentage of Total

Residential	33.96	32.75	33.25	39.47	34.38
Comm. & Inc.	63.32	64.59	64.06	58.04	63.37
Agricultural	1.75	1.69	1.72	1.51	1.68
Lighting	.97	.97	.97	.97	.57

Percentage Change over Present Revenues

Residential	-2.32	-.83	17.74	2.55
Comm. & Ind.	3.30	2.46	-7.17	1.35
Agricultural	-2.03	-.53	-12.46	-2.77
Lighting	1.27	1.27	1.27	-40.67
Total :	1.28	1.28	1.28	1.29

Note - Allocations are based on Staff's marginal costs, for comparative purposes.

Table 16 shows the results of the staff recommended allocation method at various ratios of the system average and marginal cost bases.

Table 16

Comparison of Staff's Proposed System Average/
Marginal Cost Method at Various Weightings

System Average Weight:		100%	75%	50%	25%	0%
Marginal Cost Weight:		0%	25%	50%	75%	100%
Class	Present Revenue	Revenue Allocation at Above Weighting				
Residential	$411,523	$416,840	$412,493	$408,146	$403,799	$399,452
Comml/Industr.	767,085	776,995	781,546	786,097	790,647	795,198
Agricultural	21,274	21,549	21,345	21,142	20,938	20,735
		Percent Increase Over Present Revenue				
Residential		1.29	.24	-.82	-1.88	-2.93
Comml/Industr.		1.29	1.89	2.48	3.07	3.66
Agricultural		1.29	.33	-.62	-1.58	-2.53

Note: Lighting revenue is excluded because staff proposes lighting receive system increase.

We believe now is the time to move to a marginal cost allocation of revenue for SDG&E; we will adopt a variation of the staff proposal to accomplish it. Both SCRUB and FEA are proposing marginal cost allocations, but both have inffrmitives which cause us to reject them. SCRUB's, as can be seen from Table 15, has the effect of shifting revenues between the residential and commercial/industrial classes far beyond what a marginal cost allocation should effect. As shown on Table 16 the staff's 100% marginal cost allocation has the opposite effect. FEA's proposal has the same effect as SCRUB's, although not as severe perhaps because of the two-times-system increase restriction put on by FEA. It appears that the use of total marginal cost in combination with short-run marginal cost in the case of SCRUB and the inclusion of the customer marginal cost component in the case of FEA are the cause of this effect. As pointed out by staff in its brief there are also some practical considerations not taken into account by FEA. FEA's proposal would encourage the present practice of schedule-hopping by some of SDG&E's customers and discourage others who have moved to certain schedules that are advantageous for them. The requirement of developing marginal costs for every new, innovative rate schedule could well dampen SDG&E's and staff's efforts in that direction.

We must reject SDG&E's proposed constant add-on adjustment of cents per kilowatt-hour because it does not serve to move us toward our goal of marginal cost-based rates.

We will adopt a full marginal cost allocation. But, as we discuss later, we will hold lighting rates constant until a satisfactory marginal cost showing is made for the service. Table 17 summarizes our adopted procedure and illustrates the revenue and rate effects on the various classes.

Table 17

San Diego Gas & Electric Company

Adopted Revenue Allocation

(Test Year 1984)

Class of Service	Adopted Sales (Gwh)	Present Rates - Revenue: Base ($000's)	Offset	Effective	Av. Rate (¢/kwh)	Marginal Cost Data: Short-Run Marginal Cost Rates (¢/kwh)	Marginal Cost Revenue ($000's)	Adopted Rates - Revenue: Base ($000's)	Changes (%)	Effective ($000's)	Changes (%)	Av. Rate (¢/kwh)
Residential	[illegible]	[illegible]	[illegible]	[illegible]	11.87	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	11.40
Comm. & Ind.	5555.91	307549	457928	765477	11.67	9.69	635557	327079	6.05	785007	2.55	11.97
Agriculture	175.95	5555	[illegible]	[illegible]	11.59	9.28	16607	8120	[illegible]	20512	[illegible]	11.46
Sub-Total Marginal Cost Classes	10207.95	516029	681948	1198274	11.74	—	972095	515722	.46	1200668	.20	11.77
St. Lighting (d)	100.96	6412	7094	13506	[illegible]	—	7412	.00	13506	.00	[illegible]	
Sub-Total	10308.91	525740	689040	1214780	11.79	—	—	526134	.46	1221774	.20	11.81
Resale	12	1567	6194	7761	[illegible]	—	—	1567	—	7761	—	—
Sub-Total	[illegible]	[illegible]	695234	1222541	11.86	—	—	[illegible]	[illegible]	1229535	[illegible]	11.89
Miscellaneous	—	—	6929	—	—	6929	—	6929	—	—		
Total	10320.[illegible]	534236	695234	1229470	11.92	—	—	534630	.45	1236464	.19	11.95

Notes :

(a) Total Offset Revenue for Column (3) contains .... :ECAC = 562506
:AER = 26517
:CALPAC = 2269
:ANRER = 11239
:AOR = 53416
:ERAM = 39288
:Total = 695234

(b) Column (8) = Column (10) - Column (3).

(c) Effective Revenues for MC Classes (Column 10) are allocated by the Equal-Percentage-of-Marginal-Cost (EPMC). Column (10) = (1200668)/972095) x Col. (7).

(d) St. Lighting includes : LS-1, LS-2, LS-3 , OL-1C, OL-1R, and DWL.

21.6 Future Proceedings

Between major rate cases it is necessary to adjust SDG&E's rates up and down during offset proceedings. SDG&E proposes that these rate changes be allocated on a uniform cents per kilowatt-hour basis. SDG&E claims this is consistent with current practice and will maintain a proper relationship to marginal costs.

Staff proposes the system percentage increase method to preserve marginal cost-based rate relationships.

The staff's proposal is clearly the one that will best preserve the basic relationships established by the marginal cost allocation procedure adopted for this proceeding. Ideally we would like to see marginal costs developed for each offset and major rate case proceeding. If it can be done, we would prefer that approach. If not, then the system percentage change method is preferable. Until streetlighting rates can be based on appropriate marginal costs as we discuss in Section 24.13 they will not be adjusted.

22. Electric Service Rate Schedules

SDG&E has numerous rate schedules for electric service. These will be discussed in the following sections; for reader reference, Table 18 is a summary and description of the schedules offered.

TABLE 18
Sheet 1

SAN DIEGO GAS & ELECTRIC COMPANY

SCHEDULE OF RATES

Electric

Schedule Number	Service
A	General Service
AD	General Service - Demand Metered
AL-TOU	General Service - Large - Time Metered
AL-CG	General Service - Large - Including Customer Generation
A-6 TOU	General Service - Very Large - Time Metered
A-6 CG	General Service - Very Large - Including Customer Generation
I	General Service - Interruptible
DR	Domestic Service
DM	Multi-Family Service
DS	Submetered Multi-Family Service
DT	Submetered Multi-Family Service Mobilehome Park
DE	Domestic Service to Utility Employees
LS-1	Lighting - Street and Highway - Utility-Owned Installations
LS-2	Lighting - Street and Highway - Customer-Owned Installations
LS-3	Lighting - Street and Highway - Customer-Owned Installations
OL-1	Outdoor Area Lighting Service
DWL	Residential Walkway Lighting
PA	Power - Agricultural
PG-QF	Parallel Generation - Cogeneration or Power Production
S	Standby Service
SQF	Standby Service for Cogeneration or Small Power Production
SQF-I	Standby Service for Cogeneration or Small Power Production-Interruptible
SE	Service Establishment Charge
E-PUC	Surcharge to Fund Public Utilities Commission Reimbursement Fee

TABLE 18
Sheet 2

SCHEDULE OF RATES

Electric

EXPERIMENTAL RATES

A-TOU-1	Experimental General Time-of-Use Service
A-TOU-2	Experimental General Time-of-Use Service
A-TOU-3	Experimental General Time-of-Use Service
D-ATOU	Experimental Domestic Assist Time-of-Use Service
D-UTOU	Experimental Domestic Uncontrolled Time-of-Use Service
LM-1	Experimental Peak Load Cycling
PG	Experimental Parallel Generation
PA-TOU	Experimental Power - Agricultural - Optional Time-of-Use

23. Residential Electric Rates

23.1 Customer Charge v Minimum Bill

SDG&E proposes to eliminate the customer charge for Schedules DR, DM, DS, and DT, and replace it with a minimum bill of $5 per month. SDG&E claims this would eliminate a source of continuous irritation to its customers. It would be replaced with a charge that is rarely seen by customers but provide a measure of revenue stability, eliminate a minor disincentive for conservation, and recover a reasonable amount of revenue from absentee homeowners and owners of vacation homes. No parties oppose this recommendation; WRO suggests it for gas service also.

We agree with SDG&E and will adopt its proposal.

23.2 Discounts for DT and DS Customers

Customers using Schedules DT and DS sub-meter and bill their customers at rates equivalent to Schedule DR. The elimination of the customer charge will cause a loss of revenue for DS and DT customers equal to the customer charge times the number of units they serve. Western Mobilehome Association (WMA) proposes a flat monthly discount be given DT customers of $6.51 per unit, a figure worked out by SDG&E and WMA which would offset the loss of revenue from the customer charge. Staff also recommends use of a flat monthly discount in lieu of the alternative of discounted energy rates. SDG&E further requests a 65¢ per unit discount be instituted for Schedule DS to make up the lost customer charge revenue.

We agree with both of SDG&E's proposals and they will be adopted.

23.3 Experimental Time-of-use Schedule DR-TOU-E

SDG&E proposes an experimental time-of-use schedule for residential customers. The schedule would require a $4 monthly metering charge, provide for a peak period of 12 noon to 8 p.m. Monday through Friday, excluding holidays, and be limited to 500 new customers per year. Rates would be set so that the off-peak rate would equal the baseline (or lifeline until baseline is effective) rate. The on-peak rate would be set so the average customer on the schedule would pay the average rate paid by all customers. Access to the schedule would be based on priority criteria reflecting a customer's ability to shift usage.

Staff is concerned that the $4 meter charge would discourage customers from signing up for the schedule because it would require a substantial load shift for the customer to break even with the $4 charge. As an alternative, staff suggests the energy charge cover meter costs.

WRO is adamantly opposed to the proposal on the grounds that it violates conservation principles and encourages high energy users to use more by lowering the average cost of their usage. WRO claims the goal of SDG&E's proposal is a load shift but it has presented no evidence in support of that goal. WRO points out that staff concluded the schedule would not result in any load management benefits.

We side with WRO on this issue. There is no doubt that the primary user of such a tariff would be a high energy user. This alternative would only allow such users to obtain the same amount of energy, if not more, for a lower cost. As for load shift, residential usage is not the primary contributor to the peak. Also, appropriate inverted TOU rate designs, which might overcome WRO's objections, were not presented in this proceeding. The schedule will not be authorized.

23.4 <u>Proration of Lifeline or Baseline Allowances</u>

As most utilities do, SDG&E bills it customers in cycles, reading meters each working day of the month. Therefore, bills may include sales from consecutive months with different lifeline or baseline allowances. SDG&E now uses the so-called "McKinney method." The staff recommends that a no-proration system be used. It maintains that a no-proration system is easy to understand and administer, customers will know the amount of allowances used for each bill, all customers will receive the same allowances over a period of one year, and there will be no dispute over constant or variable usage during the proration periods.

The main criticism of the staff proposal comes from both SDG&E and WRO; it concerns the possibility that two neighboring customers could have significantly different bills for the same usage in a given month. This will happen, but it is noted that just the reverse will occur at the next period of change in allowance. We are persuaded by the simplicity of the staff proposal and it will be adopted. We will make it effective on the staff's recommended date of May 16, 1984 for meters read on that date. The fall date changeover would then be six billing cycles after May 16.

23.5 Baseline Allowances

In 1982 the Legislature passed significant amendments to the Miller-Warren Energy Lifeline Act of 1975. These amendments were included in what became known as the Sher Bill. (PU Code § 739, as amended, Stats. 1982, Ch. 1541.) So-called lifeline energy allowances were changed to baseline allowances and set at:

> "...from 50 to 60 percent of average residential consumption of these commodities, except that, for residential gas customers and for all-electric residential customers, the baseline quantity shall be established at from 60 to 70 percent of average residential consumption during the winter heating season. In establishing the baseline quantities, the commission shall take into account climatic and seasonal variation in consumption and the availability of gas service. The commission shall review and revise baseline quantities as average consumption patterns change in order to maintain these ratios." (PU Code § 739(e)(1).)

The requirement in the code for relating baseline allowances to average residential consumption is one the staff recommends be met by using a bill frequency analysis. The staff's recommended method is consistent with representations made by the staff to legislative staff during development of the Sher Bill. It differs from the usual determination of the average consumption, which would be calculated by taking the total sales and dividing by the number of bills. Witness Barkovich for the staff illustrated the process on a table attached to Exhibit 50. Table 19 is an abbreviated version of Barkovich's table using assumptions deliberately designed to show, as her table did, that the bill frequency method produces a larger baseline allowance than the average bill method. This is, according to Barkovich what the Legislature intended as she testified to at Pages 4 and 5 of Exhibit 50; that is:

> "Q.10 Why did you interpret "average residential consumption" this way?
>
> "A.10 The percentages set forth in the bill to be applied to average aggregate consumption in order to determine the baseline quantity were developed from data made available by me to Legislative staff. This data was made available to try to arrive at percentages that would provide first tier sizes as similar as possible to the existing lifeline allowances while allowing for rate inversion to both induce conservation and result in revenue collection to meet appropriate revenue allocation goals. The data was based on bill frequency analysis. Therefore, bill frequency analysis should be used in implementing the bill as well."

We will adopt the bill frequency method of calculating the baseline quantity because it reflects the intent of the Legislature.

Table 19

Comparison of Baseline Allowances Provided by Average Bill Method of Calculating Baseline Allowance and Bill Frequency Method

Tier	Usage Range	Customers and Usage A	B	C	Total	Total By Tier	Cumulative By Tier	%
1	0-250	100	200	250		550	550	55
2	Over 250			450		450	1,000	100
	Total	100	200	700	1,000			

Bill Frequency Method:

Assume 55% of total usage is to be at baseline rate. Then baseline allowance is set at 250, the point at which all usage at and below that level produces 55% of total usage. Baseline usage for the three customers is:

A	100
B	200
C	250
Total	550

Average Bill Method

If the average usage times 55% is used, then the baseline allowance is 1000 ÷ 3 customers x 55% = 183. Baseline usage for the three customers is:

A	100
B	183
C	183
Total	466

SDG&E and the staff offered recommendations on the amount of the new baseline quantities. Table 20 summarizes the proposals. As Table 20 shows, staff's proposed baseline allowances are generally lower than SDG&E's. SDG&E maintains its proposed allowances will cause a less negative impact on users than the staff's. This view is concurred in by San Diego and WRO. Also, the staff witness agreed that SDG&E's proposed allowances would have less of an impact on ratepayers than those proposed by staff. We have to assume that, given the testimony of the staff that the allowances formula was worked out to cause the least disruption, the highest allowances permitted under the Sher Bill should be authorized. The recommendations of SDG&E follow that assumption and will be adopted.

TABLE 20

COMPARISON OF ELECTRIC LIFELINE/BASELINE ALLOWANCES

SDG&E'S EXISTING CLIMATE ZONES	ELECTRIC ALLOWANCES(1) (KWHR/MONTH) PRESENT LIFELINE SUMMER*	PRESENT LIFELINE WINTER*	SDG&E'S BASELINE SUMMER*	SDG&E'S BASELINE WINTER*	STAFF'S BASELINE SUMMER**	STAFF'S BASELINE WINTER**
ZONE 1						
Basic	240	240	250	250	260	270
Basic + W/H	490	490	500	800	260	270
Basic + S/H	240	790	500	800	320	600
Basic + W/H + S/H	490	1,040	500	800	320	600
ZONE 2						
Basic	240	240	300	300	330	360
Basic + W/H	490	490	550	900	330	360
Basic + S/H	240	1,040	550	900	480	895
Basic + W/H + S/H	490	1,290	550	900	480	895
ZONE 3						
Basic	240	240	300	300	330	360
Basic + W/H	490	490	550	900	330	360
Basic + S/H	240	1,360	550	900	480	895
Basic + W/H + S/H	490	1,610	550	900	480	895
A/C ZONE 1						
Basic	640	240	450	250	420	220
Basic + W/H	890	490	700	800	420	220
Basic + S/H	640	790	700	800	590	745
Basic + W/H + S/H	890	1,040	700	800	590	745

W/H = water heat   S/H = space heat   A/C = air cond.

(1) Based on Rate Schedule DR data

*From Exhibit 55, page 29

**From Exhibit 79, pages 5-8

23.6 Implementation Date for Baseline Allowances

Paragraph (d) of PU Code § 739 provides that the Commission, in the first general rate proceeding for a utility decided after January 1, 1983, shall make the new baseline allowances effective no earlier than January 1, 1984, and may make them effective any time after that.[6]

SDG&E in response to a request of the ALJ addressed this question in its brief, and the parties agree, as we do, that Section 739(d) clearly provides that the Commission may set the changeover from lifeline to baseline any time after December 31, 1983.

SDG&E proposes that the changeover be coincident with the usual changeover from summer to winter rates in the Fall of 1984. The staff proposes the changeover be made in May 1984 when the Winter to Summer change is made. We agree that it should be done in a manner that is least disruptive. This would be when lifeline allowances would have changed anyway. Also, we assume the Legislature intended that we should make the changeover as soon as possible. Therefore, the staff recommendation is the most reasonable because it provides for the changeover at the earliest time when a change would normally occur. The staff's recommendation will be adopted.

Also, in switching from lifeline to baseline we must address the resulting change in revenues because the baseline and lifeline quantities differ, thus changing the consumption level

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6 ¶ 739(d) The commission shall, after public hearings, implement the provisions of this section for each electrical and each gas corporation in an order resulting from the first general rate proceeding for that corporation decided on or after January 1, 1983, with an effective date of not earlier than January 1, 1984. Pending that effective date, the lifeline allowances existing on December 31, 1982, shall continue in effect.

billed in each tier. While the ERAM and SAM balancing accounts will rectify any over- or undercollections, we believe an adjustment should be made to rates to minimize the impact to customers. Therefore, we expect both staff and company to make recommendations for setting appropriate rate levels to take care of this problem in both the next gas and electric offset proceedings.

23.7 Climatic Zones

SDG&E presently has three climate zones. An air conditioning zone is effective in part of two of the three climate zones. Staff is proposing, with SDG&E's concurrence, that three climate zones be established as follows:

> Proposed Climate Zone 1 would include existing Climate Zone 1 customers, except those existing Climate Zone 1 customers presently in existing Air Conditioning Zone V (presently located east of Laguna Mountains);
>
> Proposed Climate Zone 2 would include existing Climate Zones 2 and 3, except for existing Climate Zone 2 customers presently in existing Air Conditioning Zone V;
>
> Proposed Climate Zone 3 would include those customers presently in existing Climate Zones 1 and 2 that are presently in existing Air Conditioning Zone V; and,
>
> The boundary between proposed Climate Zones 2 and 3 would be the western boundary of existing Air Conditioning Zone V.

The staff recommendation will be adopted.

23.8 Relationships

In addition to baseline quantities, the Sher Bill sets up criteria for baseline rate relationships.

> "The commission shall require that every electrical and gas corporation file a schedule of rates and charges providing baseline rates. The baseline rates shall apply to the first or lowest block of an increasing block rate structure which shall be the baseline quantity and shall be

established for the residential consumption of gas or electricity at a differential of from 15 to 25 percent below the system average rate. The commission, however, after a hearing on the matter, may establish baseline rates at a differential of less than 15 percent below the system average rate upon finding that such rates are necessary to insure that revenue requirements for electrical or gas service from customer classes are met or to prevent increases in rates for low priority gas customers which may cause substantial switching to other forms of energy by those customers." (PU Code ¶ 739(c).)

Staff recommends the adoption of the two-tier rates for both electric and gas services. SDG&E agrees with the staff recommendations which are to fix the first-tier rate at between 75 and 85 percent of the system average rate and set the second-tier rate to meet the revenue requirement of the residential class as determined by the adopted revenue allocation method.

However, for the gas department the staff shows in Exhibit 77 that the baseline rate exceeds 85% of the system average rate due to fuel switching. AB 2443 allows the Commission to adjust increases in rates for low priority gas customers which may cause substantial switching to other forms of energy by those customers. In D.83-06-079 we found that changes in the marketplace caused the price of oil to decline so we reduced gas rates to low priority customers and increased rates to high priority customers in order to avoid fuel switching. Because of the potential for fuel switching, and in combination with this decision's elimination of the customer charge, it may be necessary to set baseline rates at 104% of the system average. However, before implementing such a proposal, we will hold a further hearing to determine how the proposal comports with the legislative intent of AB 2443.

WRO contends that a three-tier design is preferable because it would reflect the cost of service to high energy users and discourage wasteful usage. WRO believes a high-priced third tier would be an excellent rate design alternative to promote conservation goals.

We believe the high level of SDG&E's basic rates coupled with a two-tier system will generate the the correct price signals needed to encourage conservation. We will adopt the staff proposal.

24. Commercial/Industrial Electric Rates

Commercial and industrial customers comprise about 13% of SDG&E's customers, but they account for over 60% of its sales. These customers are sold electricity through four major rate schedules, A, AD, AL-TOU, and A6-TOU. (See Table 17, Section 22.) Schedule A is an energy-only tariff with a customer charge. Schedule AD is based on energy used plus a demand factor which is based on kilowatts as measured by a demand meter but not by time of use. Schedule AD has a minimum charge based on demand. AL-TOU and A6-TOU are time-of-use (TOU) schedules which have customer charges, on-peak demand charges, energy charges, and minimum charges based on demand.

24.1 Demand Charges

SDG&E believes demand charges should be used to level its total system load profile. This can minimize the cost of current operations and the cost of future capacity. The current demand charge for Schedule AD is $4 per kilowatt and for AL-TOU it is $7.31 for on-peak demand. SDG&E claims that if a proper relationship were to be maintained between the demand charges paid by customers and the contribution of their demand to the system demand, the AL-TOU charge would have to be $7.50 per kW and AD charge $6.50 per kW. In the interest of rate stability, SDG&E proposes to increase only the AD charge from the present $4 to $5 per kW. SDG&E believes its proposal will cause AD customers to respond positively and it should aid in reducing system demand.

Staff opposes the increase in the AD demand charge and recommends that the $7.31 per kW AL-TOU on-peak demand charge be reduced to $5.31. This recommendation is consistent with the staff's general position that there should be a greater portion of the time-of-use revenue burden on the energy rate. Staff claims that once demand charges have been paid, there is less incentive for users to conserve because the average cost of electricity per kWh keeps decreasing as usage increases. Staff believes that the more one puts on the per kWh energy cost the greater the incentive for customers to cut their usage. SDG&E claims that its energy costs are so high now that there is ample reason for customers to conserve and moving some of the demand charge to the energy charge will not help.

Rock Producers supports the staff position that what customers see as they conserve when a demand charge is present is a rise in their average bill in terms of cents per kilowatt-hour. This is just the opposite of what the customers should see, claims Rock Producers. It also contends that most of the demand charges are probably based on short periods during the month when users have all their facilities running. Thus, when they take steps to conserve, the demand charge remains the same regardless of how much energy is conserved and the average charge can become ridiculously high.

We agree with the staff and Rock Producers that demand charges may stifle conservation because of their effects on the average cost of electricity. We will maintain the demand charges at their current levels.

24.2 Minimum Charges

Staff opposes the continuation of "demand ratchets" in the application of the minimum charge provisions of the AD, AL-TOU, and A6-TOU schedules. For instance, the Schedule AD minimum charge provision is as follows:

> "The minimum charge shall be $2.00 per kilowatt of the highest Maximum Demand during the preceding 11 months."

One can see that the maximum demand can "ratchet" up and down from billing period to billing period. Staff testified that the demand-ratchet provisions no longer exist for any of California's major utilities. Also, the provisions for the charge are not the same for the three schedules involved.

SDG&E wants to see the minimum charge continued. It believes the minimum charge serves to provide equitable rates to its customers and, anyway, applies only to those customers with abnormal consumption patterns. If the Commission wants to eliminate the inconsistencies, then SDG&E would recommend the wording above for all three schedules. We note this would probably increase the total charges for the other two schedules because they have provisions for 50% and 80% of the preceding 11 months, although the charge is $2.50, but at the same time continue the ratchet provisions.

Staff's proposal to eliminate the ratchet provisions is reasonable and will be adopted.

24.3 Minimum Demand Charge - Schedule AD

There is a minimum demand charge in Schedule AD which requires customers to pay $90 per month for the first 20 kilowatts or less of billing demand, with a charge of $4 for each kW over 20. SDG&E proposes to raise these charges to $110 for the first 20 kWs or less and $5 for each kW over 20. Staff proposes elimination of the charge altogether. SDG&E opposes staff but would alter its proposal to $90 for 16 ~~kW or less and $5 for each kW over 16. SDG&E claims~~ this will give the smaller customers more of an incentive to control their demand without giving them a price signal to increase consumption.

Elimination of the minimum demand charge is consistent with Commission policy. We eliminated SCE's minimum demand charges in D.92549 and Sierra Pacific Power's in D.83-04-066. We will also eliminate the minimum demand charge on SDG&E's Schedule AD.

24.4 Eligibility for Schedule AD

Schedule AD is applicable to customers whose monthly maximum demand exceeds 20 kW or whose average consumption exceeds 4,800 kWh. Staff recommends AD be modified so that customers are eligible regardless of their consumption level. This would open the schedule to any customer whose demand is in excess of 20 kW.

SDG&E points out that it could not determine whether a customer was eligible without first installing a demand meter for the customer. SDG&E claims this could mean installing meters on all Schedule A customers to determine if they met the requirement, a prohibitively expensive proposition. However, if the 4,800 kWh requirement is eliminated, as staff proposes, the only additional metering required would be for customers who use in excess of 20 kW. These are the customers who should be on Schedule AD anyway. The staff's recommendation will be adopted.

24.5 Voltage Discounts

SDG&E recommends the use of special voltage discount conditions which are consistent for all applicable schedules. The proposal would minimize confusion over the discount and equalize the discount for high voltage service for all customers regardless of the schedule through which they are served. Staff agrees that there should be consistency among the schedules; no other parties had a position. The proposal will be authorized.

24.6 Opening Schedule AL-TOU to AD and A-6-TOU Customers

SDG&E recommends, with certain limitations, that Schedule AL-TOU be made available to Schedule AD and A-6-TOU customers to give those customers a rate option. No parties oppose this proposal and it will be authorized.

24.7 New TOU Schedules

Staff recommends the study of a new small commercial customer TOU schedule and expansion of the agricultural TOU schedule. SDG&E should do this in cooperation with the staff and present it to the Commission by July 1, 1984 for consideration.

24.8 Changing Time-of-Use Periods

SDG&E and the staff propose changes in the TOU period designations now in effect. Table 24 summarizes the present and proposed periods.

Table 21

Comparison of TOU Periods

Period	Applicable on	Present*	Proposed SDG&E @	Proposed Staff @
Peak	Weekdays	S: 10a - 5p W: 5p - 9p	A: 1p - 7p	S: 11a - 6p W: 5p - 8p
Semipeak	Weekdays	S: 5p - 9p W: 10a - 5p	A: 6a - 1p A: 7p - 10p	S: 6a - 11a 6p - 10p W: 6a - 5p 8p - 10p
Offpeak	(Weekdays) (Weekends) (Holidays)	A: 9p - 10a	A: 10p - 6a	A: 10p - 6a

* Pacific Standard Time

@ Clock Time

S Summer (approximately May - Sept.)

W Winter

A All-year

The present TOU periods were established over five years ago. SDG&E believes a change should be made now to take into account current and long-term forecasts of system load characteristics. SDG&E claims its proposal, which includes having all times at the current clock time, will promote rate stability, continuity, and better customer understanding. SDG&E claims its proposed on-peak period will discourage usage at the time of the system peak and is designed to capture 95% of the weekday peaks on a yearly basis.

Staff concurs with SDG&E's proposed off-peak period and the switch to clock time but opposes SDG&E's semi- and on-peak proposals. Staff brought out in cross-examination of SDG&E's witness that the proposal for constant periods throughout the whole year, summer, and winter, required certain compromises which were unsupported by studies to show what improvements to system load characteristics would be made. But the witness also testified that there was considerable customer dissatisfaction with the present seasonal changeovers. If businesses miss these and do not change their usage practices, they could receive extraordinarily high bills. Staff believes its proposed TOU periods, coupled with discontinuance of the demand ratchet provisions of the tariffs (see Section 24.2), will help alleviate customer dissatisfaction with changeovers and correctly reflect SDG&E's system load profile.

Rock Producers took extreme exception to SDG&E's proposal to adjust the TOU periods but supports the change to clock time for all periods. It supports the recommendations of the staff. They believe SDG&E's proposal would be a severe hardship on users who have adapted their operations to the present TOU periods. Rock Producers maintains that the four considerations advanced by SDG&E in support of its proposal, system operating characteristics, stability, continuity, and customer understanding, do not, in fact, support the proposal. Rock Producers claims the proposed on-peak period does not reflect the system demand curve, would include a large number of inappropriate hours in the non-peak, and require users to pay for on-peak charges during periods when there is no peak demand on the system. Rock Producers turns SDG&E's stability argument around by maintaining that adoption of the staff proposal will maintain stability whereas SDG&E's proposal would accomplish just the opposite. The continuity that would result from year-around TOU periods appears, at least to Rock Producers, to be for the benefit of SDG&E and not its customers. Finally, Rock Producers claims there is no customer confusion because the present times have been in effect a long time; and if there might be some confusion, the proposal of the staff should help to clear it up.

Applying some arithmetic to the present TOU schedule and those proposed by SDG&E and the staff indicates the following percentages for TOU hours per year by period if summer months are assumed to total 5 and winter 7:

		Proposed	
Period	Present	SDG&E	Staff
Peak	15%	17%	13%
Semi-peak	17%	29%	33%
Off-peak	68%	54%	54%
	100%	100%	100%

In both the SDG&E and staff proposals there is a significant shift away from the off-peak. The staff offsets the possible effect on billings by reducing the peak hours by about 13%, whereas SDG&E increases them by about the same percentage. Rock Producers' witness testified that in one case, one of its members under SDG&E's scheme would suffer an increase in charges for service of 69% assuming no change in patterns or amount of usage. We cannot believe that a knowledgeable customer would let that happen, but it does serve to illustrate the problems customers will have with SDG&E's proposal and what will undoubtedly be a scramble to change usage patterns and, perhaps, tariffs.

Based on the staff analysis contained in Appendix B of Exhibit 74, we find staff's proposal is the proper one for this proceeding and it will be adopted. We believe it more correctly reflects SDG&E's system load profile and will effectively assist in smoothing that profile. Also, it will provide more accurate pricing signals to SDG&E's customers of the cost of their usage, particularly during the semi-peak hours.

24.9 TOU Rate Differentials

SDG&E proposes the on-peak and semi-peak rates be 3.0¢ and 2.4¢ per kWh higher, respectively, than the off-peak rate. Staff proposes that ratios be used in lieu of actual ¢/kWh. The primary differences in the two proposals arise from the marginal cost methods used and the ¢/kWh SDG&E maintains between TOU periods. SDG&E uses only marginal energy costs and the staff uses both marginal energy and demand costs. Because there is a demand rate component included in the rate schedules for these services, it would be inconsistent to use the energy plus demand marginal cost approach in determining the differential. Therefore, we will adopt the company's method. To maintain rate continuity it will be applied as a percentage difference based on the relationships of on-peak, semi-peak, and off-peak total rates (base plus ECAC and AER) as of January 1, 1984.

24.10 TOU Rate Differentials in ERAM or ECAC

Time-of-use rate differentials between on-peak, semi-peak, and off-peak are currently reflected in base rates for nonresidential customers and collected subject to the electric revenue adjustment mechanism (ERAM) balancing account. Staff recommends the differentials be reflected in ECAC rates instead. Staff bases its recommendation on its belief that the greater frequency of ECAC adjustments will provide a better opportunity to adjust TOU differentials based on updated marginal costs and customer sales estimates. SDG&E points out that ERAM rates are adjusted at the same time as ECAC rates and, therefore, sees no benefit from the proposal. The staff has not shown any real need for the change and it will not be adopted.

24.11 Limiting Schedule AL-TOU Customers

SDG&E proposes to limit Schedule AL-TOU to 500 additional customers per year. No parties object to the proposal. To limit the schedule, SDG&E proposed priorities for allowing customers on the schedule. The proposal, including the priority criteria, will be authorized.

24.12 Combining Schedule LS-3 with Schedules A and AD

SDG&E proposes to combine Schedule LS-3 with Schedules A and AD. LS-3 is a metered lighting service schedule that has been closed to new customers since June 1979. New customers with installations similar to those now on LS-3 are served on Schedules A or AD at almost identical rate levels. Thus, SDG&E believes LS-3 should be discontinued and its users transferred to A and AD. Staff recommends that many of the larger LS-3 customers could benefit from a time-of-use tariff. SDG&E proposes to make Schedule AL-TOU available as an option to AD customers (Exhibit 55, Page 12). Schedule LS-3 will be continued at its present level pending resolution of the issues discussed in Sections 24.13 and 24.7.

24.13 Lighting Rates

Streetlighting rates received another brushoff from SDG&E and the staff in this proceeding. We borrow liberally from San Diego's brief in our discussion of this issue.

In A.59788, SDG&E's 1982 rate case, the evidence showed that the outdoor and streetlighting rates produced substantially more than SDG&E's full marginal cost study indicated was appropriate. The Commission questioned the accuracy of the marginal cost studies for the lighting schedules and ordered a system average increase be imposed in D.93892 in the 1982 case. The Commission also ordered, in that decision, that SDG&E provide a comprehensive study on lighting marginal costs for the lighting schedules. SDG&E did not provide such a study in its NOI or application filings, but did provide a study of sorts to San Diego and the Commission during the hearings on this application.

This record shows from exhibits of witness Lim for the Federal Executive Agencies that lighting revenues are far beyond those justified by marginal cost relationships. Using Exhibit 61 of SDG&E witness Hansen, which reflects an electric service revenue increase of \$68.6 million, and using SDG&E's marginal costs, proposed streetlighting rates, based on an overall system percentage increase as proposed by SDG&E and staff, are 122% higher than marginal costs. This compares to residential, commercial/industrial, and agricultural, based on the same data, of between 31 and 34% higher.

SDG&E gave no adequate explanation of why it did not follow the Commission's direction in D.93892 to provide a comprehensive study on marginal costs for the lighting schedules. Staff said it did not have time. Both SDG&E and staff are taking the easy way out again and recommending application of the system percentage increase.

Staff suggested, in Exhibit 74, that an alternative for those lights which are owned by SDG&E is deregulation. This was explored with the staff witness by questions from the ALJ. Staff conceded that it would be reasonable to write off such lights, getting them out of the rate base and dealing with power costs only.

If we were to take the only reasonable showing on the proper level of lighting rates in this record, we would have to order a decrease in the rates. However, in view of the effect it would have on ratepayers in other categories and the fact that the marginal cost data for streetlighting is incomplete, we will not change the lighting rates in this proceeding.

In so doing, we put SDG&E and the staff on notice that we want a complete marginal cost study of lighting rates in the 1986 SDG&E rate case and a showing on the reasonableness of deregulating utility-owned streetlights.

24.14 <u>Interruptible and Customer Generation Service</u>

Staff recommends review of Schedule I, which covers interruptible service, and Schedules AL-CG and A6-CG, which cover customer generation, for SDG&E's next general rate case. Staff specifically requests that SDG&E identify potential customers for the interruptible schedule in the event of needed capacity, modify the schedule to include provisions for frequency of interruption, duration of interruption, and notice provided customers, and adjust the discount so that it reflects SDG&E's marginal costs, and review and update Schedules AL-CG and A6-CG to be consistent with Schedule AL-TOU and A6-TOU changes. Staff's recommendation is appropriate and will be adopted.

24.15 Agricultural Schedule PA-TOU

Staff recommends that Schedule PA-TOU rates be developed assuming 30% of the sales are on peak, and that any expansion of PA-TOU as a nonexperimental schedule be based on its being revenue neutral for the schedule's customers. Staff bases its recommendation on a review of recorded data filed with the Commission for December 1982 through March 1983 under requirements of Commission GO 65-A. Staff's proposal is reasonable and its alternate rate design No. 1 as shown on Table 3 of Exhibit 75 will be adopted.

25. Gas Service Rate Design

SDG&E's gas service is provided through the 16 schedules shown on Table 22.

TABLE 22

SAN DIEGO GAS & ELECTRIC COMPANY

SCHEDULE OF RATES

Gas

Schedule Number	Service
GR	Domestic Natural Gas Service
GM	Multi-Family Natural Gas Service
GS	Submetered Multi-Family Natural Gas Service
GT	Submetered Multi-Family Natural Gas Service - Mobilehome Park
GN-1	Commercial and Industrial Natural Gas Service
GN-2	Commercial and Industrial Natural Gas Service
GCG	Cogeneration Natural Gas Service
GN-3	Commercial and Industrial Natural Gas Service
GN-36	Commercial and Industrial Natural Gas Service
GN-4	Commercial and Industrial Natural Gas Service
GN-46	Commercial and Industrial Natural Gas Service
GN-5	Natural Gas Service to Utility Electric Generating Stations
G-90	Service to Utility Employees
G-91	Service Establishment Charge
GL-1	Service from Liquefied Natural Gas Facilities (Borrego Territory)
G-PUC	Surcharge to Fund Public Utilities Commission Reimbursement Fee

SDG&E and staff made different proposals for gas rate design guidelines. SDG&E proposes using the Commission's previously adopted rate design guidelines which are:

a. No increase to the Schedule GN-1 customer charges. Increase only the commodity rates.

b. Set the lifeline rate at approximately 80% of the average system rate (the average system rate is the total revenue requirement divided by total sales).

c. Set Schedules GN-3 and GN-4 rates to approximate the estimated current price of No. 2 fuel oil.

d. Set the Schedule GN-5 rate to approximate the price of No. 6 fuel oil.

e. Invert residential blocks with the last block having the highest rate.

f. Set the Schedule GN-1 and GN-2 rates relatively near to the modified average system rate (less lifeline sales and revenues) to recover the remaining revenue requirement (Ex. 56, p. 2).

Staff recommends the following changes to this approach:

a. Estimate the price of No. 2 fuel oil.

b. Establish the GN-5 rate.

c. Adjust SC-176 and G-91 rates as required.

d. Calculate other revenues.

e. Set the retail rate residually after allowing for GN-1 customer month revenue.

f. Set the residential rates so that the baseline/non-baseline ratio approximates 1.5 with the baseline rate being 75%-85% of the system average rate, if feasible. Minor adjustments to the non-baseline rate may be made to balance the revenue requirement (Ex. 77, p. 2-3).

Although the staff rate design witness testified that his proposal should encourage customers with alternative fuel capabilities to remain on or return to SDG&E's system, we see no advantage in changing the general guidelines. We will adopt SDG&E's guidelines.

25.1 Customer Charge

SDG&E proposes elimination of the customer charge from Schedules GR, GM, GS, and GT for many of the same reasons as its recommendation under electric service. Staff recommends the charge be increased from $1.70 to $3.10. SDG&E claims this rate component is no longer needed for revenue stability because of the Supply Adjustment Mechanism. Also, a customer charge has the effect of discouraging those who use gas only for space heating from turning off their pilot lights in the summer. We will accept SDG&E's proposal and eliminate the charge.

25.2 Residential Blocking

Staff proposes the present Tiers 2 and 3 be combined into a single tier. No one opposes; it will be adopted.

25.3 Discounts for Schedules GS and GT

By eliminating the customer charge (Section 25.1) Schedules GS and GT customers (submetered service) will be affected because they bill their customers on rates equivalent to Schedule GR. This causes a loss of revenue for GS and GT customers equal to the customer charge times the number of units they serve. This is the same situation that was discussed under electric rates in Section 23.2. As in that case, WMA proposes a flat monthly discount be given to GT customers of $4.88 per unit in lieu of a discounted energy rate. SDG&E also recommends establishing a 65¢ per unit discount for Schedule GS customers for the same reason. The $4.88 and 65¢ proposals are reasonable and will be adopted.

25.4 Schedule G-91 Service Establishment Charge

Staff recommends increasing the Schedule G-91 service establishment charge from $8.40 to $15 in order to transfer noncommodity costs and expenses for establishing service from commodity to noncommodity rates. Staff claims this is a proper allocation of costs of service. Although SDG&E did not present any evidence on the change, it requests that ~~no change be made because~~ the charge was just adopted in June 1983. The basis for the staff proposal is sound and the charge will be increased to $15.

25.5 Modification of Rule 2

SDG&E proposes a modification to its Gas Department Rule 2 to conform to its Electric Department Rule 2. Rule 2 covers charges for customers requiring special facilities for unusual circumstances. There are no objections to the proposal and it will be authorized.

25.6 Seasonal Proration of Bills

The same proposals and the same arguments were made by the parties concerning proration of gas bills for lifeline or baseline allowances as were made for the Electric Department. As we did in Section 23.4 for the Electric Department, ~~we will adopt the staff~~ proposal including the changeover date for baseline from lifeline.

25.7 Gas Climatic Zones

Staff proposes another climate zone be established for gas service in the Borrego area east of the Laguna Mountains because there is a separate electric climate zone proposed for that area. SDG&E opposes staff's proposal. It maintains that the present single climatic zone for all customers is easy ~~to administer, and the~~ creation of a separate zone would cause a small group of customers to have higher bills than other customers on the system for no good reason. Staff's proposal will not be adopted.

25.8 Gas Baseline Volumes

SDG&E and staff, as they did for electric service baseline volumes, made decidedly different recommendations for gas baseline volumes. Staff's are below SDG&E's proposals by a range of 7 to 27% for a typical customer. For the same reasons we outlined in Section 23.5 under electric rate design, we will adopt the company proposal.

This will minimize any negative impacts from the imposition of baseline allowances.

26. Steam Service Rate Design

Both SDG&E and the staff concur, as we do, that steam rates should be changed on a uniform dollar per thousand pound basis.

26.1 Steam Revenue Adjustment Mechanism (SRAM)

SDG&E proposes an SRAM procedure that would conform its steam tariffs with its electric and gas tariffs. SRAM would be coupled with the ECAC procedure for hearing and disposition by the Commission. SRAM would operate in the same manner as the Supply Adjustment Mechanism (SAM). Staff does not object to the proposal but recommended two modifications which SDG&E agrees to. No other parties commented on the proposal. We will adopt SDG&E's proposal as set forth in Exhibit 57 at pages 7 and 8 as modified by staff's recommendations in Exhibit 77 at page 5-2.

26.2 Authorized Steam Losses

SDG&E proposes doubling its authorized steam losses from 25 million pounds per year to 50 million. Staff proposes it be raised to 27.5. These losses are due to condensate losses and metering errors. The record indicates that, based on recent company reports and data, the staff's estimate is more reasonable. It will be adopted.

27. Proposed Tariff Rule Changes

WRO proposes seven changes in SDG&E's current tariff rules that it deems are necessary to provide fair and equitable treatment of SDG&E customers. They are:

a. Require SDG&E to obtain Commission approval before termination of elderly, youthful, or handicapped customers.

b. Provide for disclosure on notices and bills that multilingual individuals are available at SDG&E to translate to Spanish and any other language widely spoken within SDG&E's service area.

c. Extend the deadline for requesting an installment plan.

d. Expand the time within which SDG&E must make its personal contact attempts.

e. Prohibit the shutoff of service to seriously ill customers.

f. Establish a minimum past due amount prior to termination.

g. Allow the initiation of a deferred payment plan in lieu of full deposit of the amount of a disputed bill to initiate the complaint procedure with the Commission.

WRO in addition to briefing the above proposals and expanding on them in oral argument, called as its witness David Durkin. Durkin sponsored three exhibits in support of WRO's proposals.

Many of the changes proposed by WRO were considered in OII 49 which culminated in D.93533 dated September 15, 1981. But the specific proposals of WRO were not all covered in that proceeding or decision.

One issue not included above involved SDG&E's Rule 11-C which provides for denial or discontinuance of service for acts of a customer or conditions on a customer's premises which indicate an intent to defraud the utility. Although the record appears to indicate that this dispute had been settled, WRO brought it up strongly again in its brief. SDG&E had worked with the counsel for WRO to develop specific criteria for implementation of the rule. Witness Beyer for the company confirmed that SDG&E explicitly follows the criteria and witness Durkin for WRO acknowledged that he had no problem with discontinuances for any of the actions contained in the criteria, nor did he have problems with the internal practices of the company in using the criteria. The only dispute that seems to be left is that WRO believes SDG&E should be required to provide customers with the reason for termination prior to the scheduled termination date. This appears to be a quite reasonable requirement and we will order SDG&E to include such a provision in its tariffs.

Change (a) proposed by WRO is entirely unworkable from the Commission's standpoint. We just don't have the staff to review the factual matters surrounding terminations. If this were expanded to all utilities, which would be the logical next step, it would require a prohibitively large staff even if it were limited to elderly, youthful, or handicapped. Disputes of this kind might also require a hearing, a process now initiated through complaint procedures. The cost of additional hearing officers and backup staff have not been considered by WRO. Change (a) will not be approved.

Change (b) has been considered in OII 49 and we consider D.93533 to be dispositive of that issue. The usual procedures are available if WRO wishes reconsideration.

Change (c) is reasonable and will be adopted. We agree with WRO that customers should be given every opportunity to maintain their service. Therefore, SDG&E should allow customers the payment plan option up to, and including, the expiration date of the final notice prior to termination.

Change (d) involves SDG&E's Rule 11-A which provides that the utility make a reasonable attempt to personally contact customers either by telephone or in person at least 24 hours prior to termination. WRO proposes the time be expanded to 48 hours, the time required for elderly and handicapped customers now. The proposal seems fair and reasonable and will be ordered.

Change (e) is already in effect at SDG&E. WRO claims it is a matter of the emphasis and notice given the rule by SDG&E. WRO proposes a rule to rectify what it considers SDG&E's shortcomings in application. A rule similar to WRO's proposed Rule 11-D in Exhibit 105 is reasonable and should be incorporated in SDG&E's tariffs.

For change (f), WRO proposes that a customer would have to have a bill in excess of $25 before SDG&E may shut off service. WRO argues for this rule on the basis that it would most likely be applied in cases where a customer is out of town or a low-income customer makes a partial payment on a bill. We think the out-of-towners should face their responsibility for the bill in or out of town. For the partial-payment customers there are other remedies available, some already discussed in this section, for avoiding shutoff. Change (f) will not be ordered.

Change (g) seems eminently fair and we wonder why it was not considered in OII 49, if it was not. It will be ordered.

We will order SDG&E to make the changes noted above, not only in its tariffs, but in its so-called "Financial Division Standard Practice Manual." SDG&E will also be ordered to make clear, early in negotiations over past-due bills, that installment options are available.

28. Female and Minority Business Enterprises

In D.82-12-101, in Case 10308, the Commission ordered the staff and various utilities to develop, in their next general rate increase proceedings, a recordkeeping system to monitor the utility's female and minority business enterprises activities. SDG&E and the staff cooperatively developed the reporting procedure shown in late-filed Exhibit 120, and they stipulate that it resolves the only issue in this area.

29. Qualifying Facilities Payments

SDG&E witness McKinnon sponsored Exhibit 103 regarding capacity payments to qualifying facilities (QFs) in compliance with D.82-12-120. Staff Exhibit 74, Table 1-11, presented the levelized costs of a combustion turbine consistent with D.82-12-120, but did not reflect the probability of SDG&E needing additional capacity. Exhibit 103 provides capacity payments adjusted for probability of need in a reasonable manner. The payments shown on Table 1 of Exhibit 103 will be adopted.

Staff Exhibit 74, Table 1-12, provides incremental heat rate (IHR) factors for QF energy prices, the only IHR factors submitted in this case. D.82-12-120 Ordering Paragraph 12.e. directs that utilities shall use the average year IHRs as determined in the most recent general rate case for the derivation of energy prices. Ordering Paragraph 12.f. of D.82-12-120 provides that utilities shall propose incremental heat rate revisions in ECAC proceedings after new power plants come on line. Our discussion on Page 31 of D.82-01-103 makes it clear that the impact of major new units shall be included in the calculation of energy prices only when actual operational experience can be used to assess the impact on marginal energy costs. Therefore, for the purpose of QF pricing, we will adopt IHRs without SONGS Units 2 and 3 (see Table 1-12 of Staff Exhibit 74).

30. Attrition

There are three issues regarding the proposed Attrition Mechanism for 1985: the escalation rates to be employed, the manner of forecasting rate base additions, and the identification of fixed expenses not subject to the Attrition Mechanism.

The first two issues have been decided elsewhere in this decision by our adoption of the company's method for escalation and the staff's method of estimating rate base. On the third issue, we will adopt the staff proposal because it appears to accomplish the fine tuning required.

In addition, we have separately provided SDG&E the opportunity to include a postal rate increase in the company's attrition filing. Therefore, we will consider all postal expenses as a fixed item not subject to indexing.

The details of attrition mechanism calculations are shown in Appendix F.

Findings of Fact

1. SDG&E filed this application in compliance with the requirements of Resolution ALJ-149 as amended by D.82-12-072 and D.83-01-001, which is the Commission's Rate Case Plan.

2. By this application, SDG&E requests annual increases for test year 1984 of $65.3 million, $54.5 million for its Electric Department, $10.7 million for its Gas Department, and $0.1 million for its Steam Department.

3. Between March 28 and October 12, 1983, 66 days of public hearings were held, including oral argument before the Commission en banc, at which all parties, including the public, were given an opportunity to participate.

4. SDG&E and the staff stipulated to the estimates for electric, gas, and steam sales for the test year, which no other parties contested, and which are satisfactory for developing estimates of revenues under present rates for the test year.

5. In spite of the stipulation noted in Finding 4, SDG&E and the staff do not agree on a method for forecasting sales and revenues.

6. It would be advantageous from the standpoint of hearing time if parties could come to stipulations such as the one noted in Finding 4, early in the proceedings.

7. SDG&E's recommendation that its ERAM procedure be expanded to include resale revenues should not be adopted because such revenues are not under this Commission's jurisdiction.

8. The DRI method of developing escalation factors for labor more accurately reflects SDG&E experience and the results produced for ratemaking purposes are more reasonable than the staff's.

8a. The DRI method of developing nonlabor escalation factors can be modified to reflect SDG&E's experience and to permit other parties to check the results of the method without undue effort. The results of the modified DRI method are reasonable for ratemaking purposes.

9. The SDG&E construction escalation factors are reasonable for this proceeding.

10. SDG&E will not incur any increased communication costs as a result of the divestiture of PT&T from AT&T.

11. SDG&E's Intermediate Range Planning process may be a good management tool but has yet to be verified.

12. In general, the staff's estimating methods are more sound than SDG&E's and will give SDG&E the resources it needs to properly carry out its administrative activities without requiring the Commission to approve specific SDG&E projects.

13. SDG&E unforeseen expense estimate factors are unnecessary additions to its basic estimates for the accounts involved.

14. D.93892 in SDG&E's 1982 major rate case was dispositive of SDG&E employee perquisites.

15. Only postal increases that have been officially announced should be included in 1984 test year expenses.

16. Staff's estimates for office supplies and expenses correctly reflect this Commission's ratemaking policies.

17. With the exception of the effect of the staff's proposed pension fund penalty, the staff's estimates for Account 922, Administrative Expenses Transferred, are reasonable for the test year.

18. The staff's estimate for Account 922, Consultant Fees, is reasonable for the test year but must be escalated to 1984.

19. The staff's proposed pension fund penalty is not proper because the staff has not shown that SDG&E's pension fund performance is not satisfactory.

20. SDG&E management should have the discretion of requiring special physical examinations of its top-level management employees; for this proceeding the cost of $8,000 is reasonable.

21. Estimated allowable expenses for Account 926, Pensions and Benefits, of $24,967,600 is reasonable for the test year.

22. The staff adjustments to Account 930, Association Dues and Expenses, are proper.

23. Staff estimates for Account 930, Stock and Debt Securities Expense, are reasonable for the test year.

24. Staff's estimate for Account 930, Shareholder Reports Expense, as escalated by the escalation factors adopted in this decision, is reasonable for the test year.

25. Staff's estimate for Account 930, Bank Fees, is reasonable for the test year.

26. The amount of $14,613,000 for Research, Development and Demonstration is reasonable for the test year.

27. In connection with its RD&D activities:

a. For future rate cases SDG&E should provide RD&D estimates in constant year dollars for labor versus nonlabor and other.

b. SDG&E's future filings and April 15 annual RD&D report should be in the format shown in Appendix D of Exhibit 45 including the information requested by staff on pages 2 and 3 of Exhibit 45 consistent with D.82-12-005.

28. Staff's estimates for the following Electric Department expense accounts are reasonable for the test year:

Account 512, Boiler Plant Maintenance
Accounts 513 and 553, Turbine Maintenance
Account 517 , Supervision and Engineering
Account 518, Non-ECAC Fuel Expense
Account 588, Miscellaneous Distribution Expenses
Account 593, Maintenance of Overhead Lines

29. SDG&E incurred an expense of $14,572,000 for resleeving of the SONGS 1 steam generator unit of which $7,034,000 will have been written off by the end of 1983.

30. There is $7,538,000 left to write off from the SONGS 1 resleeving project and it is reasonable to write that amount off equally in the years 1984 and 1985, subject to refund.

31. For attrition year 1985, the SONGS 1 resleeving writeoff noted in Finding 30 should be treated as an extraordinary expense.

32. The SONGS 1 resleeving expenses referred to in Findings 29, 30, and 31 should be made subject to refund pending the outcome of the Commission's investigation into the reasonableness of Edison's pursuit of litigation against the SONGS 1 contractor for the resleeving project.

33. When the Commission issued D.93892, SDG&E had some fixed wheeling contracts which were unsigned and which the Commission authorized SDG&E to carry on its books for eventual recovery in this rate case.

34. SDG&E interpreted the Commission's intent concerning the contracts noted in Finding 33 as being applicable to all of its wheeling contract expenses, even those included in 1982 and 1983 test years, which was not the Commission's intent.

35. It was the Commission's intent that any interest on the authorized expenses noted in Findings 33 and 34 should be calculated using the usual method of the 90-day commercial paper rate.

36. Findings 33, 34, and 35 result in an adjustment to SDG&E's estimate for Account 565 of $709,200; with that adjustment, SDG&E's estimate for Account 565 is reasonable for the test year.

37. The stipulation reached by SDG&E and the staff on base estimates of test year gas supply, gas storage, and gas transmission expenses are reasonable for the test year.

38. Staff's estimates for the following Gas Department expense accounts are reasonable for the test year:

Account 870, Supervision and Engineering
Account 879, Customer Installation Expense

39. An amount of $1,141,000 for Account 880, Other Operations Expense, is reasonable for the test year.

40. Steam Department operating expenses stipulated to by SDG&E and the staff are reasonable for the test year.

41. SDG&E's method for estimating ad valorem taxes is reasonable for the test year.

42. SDG&E's method for estimating payroll and miscellaneous taxes is reasonable for the test year.

43. The staff method for calculating income taxes for the test year is reasonable.

44. It is appropriate not to consider the effects of the Tax Equity and Fiscal Responsibility Act of 1982 in this decision.

45. The SDG&E and staff methods for calculating depreciation expense provides an equitable and reasonable allocation of expense to the test year.

46. With the exceptions noted in the following findings and an appropriate escalation of Other Additions to plant, the staff estimate of plant for rate base purposes is reasonable for the test year.

47. The staff's proposed adjustment for SONGS common plant is not appropriate and will not be adopted.

48. Staff's estimates for property held for future use, including exclusion of the Valley Center Substation parcel and the Silver Gate Power Plant turbine shell, are reasonable for the test year.

49. With the exception of those attributable to the Gas Department, the staff adjustments to plant for the capital savings accruing from the implementation of DEIS are proper.

50. The staff's proposed reduction to materials and supplies allowance because a portion may be related to construction projects is not proper.

51. Staff's estimate for undistributed fuel expense represents actual conditions and is reasonable for the test year.

52. The working cash allowance methods and/or estimates used by SDG&E for escalation, clearing accounts, and miscellaneous debits are proper for the test year.

53. In May 1978, SDG&E cancelled its Sundesert nuclear power plant project.

54. By D.90405 dated June 5, 1979 in SDG&E's A.58607, the Commission found that SDG&E management was not imprudent in its inception, continuation, and termination of Sundesert considering the circumstances that existed at the time SDG&E had to make its decision, and the Commission authorized the five-year writeoff of $37.2 million of non-site-related costs and the inclusion of $45 million of site-related costs in property held for future use which is now known as the Blythe Site.

55. By D.93892 in SDG&E's 1982 rate case the Commission included the Blythe Site in rate base but at the 1979 test year authorized rate of return of 10.59%.

56. By D.93892, the Commission placed SDG&E on notice that it must come up with a specific plan for the Blythe Site in its 1984 test year rate case, the instant proceeding, if it is to be included in rate base.

57. In D.93892 the Commission told SDG&E to show the following in its 1984 rate base concerning the Blythe Site:

a. A detailed specific plan for use of the site.

b. The need for additional generation capacity.

c. The availability of alternative resources.

d. Any economic benefit from retaining the site in rate base.

58. SDG&E has no more than a general plan for the use of the Blythe Site.

59. The role of the Blythe Site in satisfying SDG&E's future generation capacity needs is unclear.

60. The availability of alternative resources to the Blythe Site at the time SDG&E would expect it to go into operation is unclear.

61. Based on the record in this case, the issue of disposition of the Blythe site needs further exploration at hearing before a decision can be made.

62. It is reasonable to continue the ratemaking treatment for the Blythe site authorized in D.93892.

63. SDG&E's proposal for allocation of the gain from the sale of the Sorrento East property is reasonable.

64. The staff's capitalization ratios and costs for long-term debt and preferred stock are reasonable for the test year.

65. A return on equity capital of 16% and an overall rate of return of 12.82% for the test year is reasonable.

66. The time has come to make some cutbacks in conservation expenditures at SDG&E.

67. Conservation programs should be designed to produce fair and reasonable rates for all ratepayers.

68. A reasonable policy for conservation, load management, and cogeneration for SDG&E is the one set out in Section 15.1.10 of this decision.

69. Conservation measurement and cost-effectiveness tests should be reviewed and proposals made for their use which serve, in as practical a way as possible, the conservation policy we have outlined for SDG&E in this decision.

70. SDG&E has not deliberately tried to discourage cogeneration and the penalty recommended by the staff is not proper.

71. The staff's recommended penalty for SDG&E's alleged substandard performance in the area of load management has no basis in fact, is unreasonable, and should not be assessed.

72. The maximum expenditures for conservation, cogeneration, and load management by SDG&E for the test year should be $ 20,836,000 as shown on Table 11 of this decision.

73. The adopted results of operations shown on Table 12 of this decision are reasonable for the test year 1984 and the revenues generated should enable SDG&E to earn the authorized rate of return of 12.82%.

74. The marginal cost showings of the staff for electric and gas service are reasonable for the purposes of this proceeding.

75. It is appropriate in this proceeding to move to a marginal cost allocation of revenues.

76. In offset proceedings requiring adjustment of rates between major rate cases, the system percentage change method should be used if a current marginal cost study is not available, except for lighting rates, which will not be adjusted until marginal cost studies are made.

77. SDG&E's proposal for a minimum residential bill in lieu of a customer charge is reasonable and should be adopted.

78. Because the customer charge is eliminated, it is reasonable to give DT customers a discount of $6.51 per unit and DS customers a discount of 65¢ per unit.

79. SDG&E's proposed experimental Schedule DR-TOU-E should not be authorized because it violates conservation principles and encourages high energy users to use more energy.

80. The staff's proposal for nonproration of lifeline/baseline volumes during periods of changeover is reasonable and should be adopted.

81. The bill frequency method of calculating baseline average consumption is proper because it reflects the intent of the Legislature.

82. SDG&E's proposed baseline allowances appear to have the least impact on users, however, before implementing the proposal for the gas rates, further hearings are necessary to determine how the proposal comports with the legislative intent of AB 2443.

83. The staff's proposed time for implementation of baseline allowances should be adopted because it is the earliest time a change can be made without severe disruptions.

84. The staff's recommended changes in climatic zones for electrical service are reasonable and should be adopted.

85. The staff proposal for rate relationships under the Sher Bill is reasonable.

86. Demand charges may stifle conservation because of their effect on the average cost of electricity.

87. SDG&E's proposed demand charge for electric service Schedule AD should not be adopted.

88. A minimum charge coupled with a demand ratchet provision is unreasonable and should be discontinued.

89. SDG&E's minimum demand charge change in Schedule AD should be eliminated.

90. The staff's proposal for expanding the customers eligible for Schedule AD is reasonable and should be adopted.

91. SDG&E's proposal for the use of special voltage discount conditions which are consistent among tariffs is reasonable and should be adopted.

92. SDG&E's recommendation that Schedule AL-TOU be made available to Schedule AD and A-6-TOU customers is reasonable and should be adopted.

93. The staff's proposed time-of-use periods should be adopted because they more correctly reflect SDG&E's system load profile than the present periods or those proposed by SDG&E, and they will provide more accurate pricing signals to SDG&E customers than those now in effect.

94. The time-of-use rate differentials proposed by SDG&E should be adopted because they correctly reflect only marginal energy cost; the differentials should be maintained at the percentage relationships existing between total rates at January 1, 1984.

95. Staff recommends that time-of-use rate differentials be reflected in ECAC rates instead of base rates, but it has not shown any real need for the change and it will not be adopted.

96. SDG&E's proposal for limiting the customers on Schedule AL-TOU including the criteria for eligibility are reasonable and should be adopted.

97. SDG&E and staff should cooperatively develop a new small commercial customer time-of-use schedule and an expansion of the agricultural time-of-use schedule and present them by July 1, 1984 for Commission consideration.

98. Schedule LS-3 should be continued pending establishment of the schedules referred to in Finding 100.

99. SDG&E lighting rates are much higher than would be justified by marginal cost relationships.

100. There are no adequate data in the record to determine the level of lighting rates necessary to properly reflect marginal costs, and therefore, there should be no increase in lighting rates in this proceeding.

101. SDG&E and the staff should be ordered to prepare and present marginal cost studies for lighting services in the next SDG&E rate case; the studies should consider ownership by users of facilities now owned by SDG&E.

102. Staff's recommendation that SDG&E review its interruptible and customer generation service schedules as discussed in Section 24.14 is reasonable and should be adopted.

103. Staff's recommended rate design for Schedule PA-TOU as discussed in Section 24.15 is reasonable and should be adopted.

104. SDG&E's gas rate design guidelines are reasonable and should be adopted.

105. SDG&E's proposal to eliminate the customer charge for gas service for the same reasons as for electric service is reasonable and should be adopted.

106. Staff's proposal that the present gas service Tiers 2 and 3 be combined into a single tier is reasonable and should be adopted.

107. Because the customer charge is eliminated, it is reasonable to give GT customers a discount of $4.88 per unit and GS customers a discount of 65¢ per unit.

108. The staff recommendation that the Schedule G-91 service establishment charge be increased to $15 is sound and should be adopted.

109. SDG&E's proposal to modify its Gas Department Rule 2 so it corresponds to its Electric Department Rule 2 is proper and should be authorized.

110. Because staff gives no good reason for its proposal to establish another gas climatic zone in the Borrego area it should be rejected.

111. Steam rates should be changed on a uniform dollar-per-thousand-pound basis.

112. SDG&E's proposed SRAM will conform its steam tariffs with its gas and electric tariffs and should be approved with the modifications proposed by staff.

113. Based on the reports and data made available recently, the staff's proposed authorized steam losses level is more reasonable than SDG&E's proposal and should be adopted.

114. It is reasonable to require SDG&E to provide customers with the reason their service is being terminated prior to termination, and SDG&E should be ordered to include that provision in its tariffs.

115. WRO's proposal that SDG&E obtain Commission approval before terminating service to elderly, youthful, or handicapped customers is administratively unworkable at this time and should not be required.

116. WRO's proposal concerning multilingual notice by SDG&E was considered by the Commission and disposed of in D.93533.

117. SDG&E should allow customers its payment plan option up to, and including, the expiration date of the final notice prior to service termination.

118. SDG&E's Rule 11-A should be revised so that the 48-hour provision is applicable to all customers.

119. To improve the clarity and emphasis of SDG&E's shutoff procedures for service to seriously ill customers, a rule similar to WRO's proposed Rule 11.1 in Exhibit 10 is reasonable and should be incorporated in SDG&E's tariffs.

120. WRO's proposal that customers must have a bill outstanding of at least $25 before service may be shut off is not reasonable and should not be adopted.

121. It is reasonable to allow the initiation of a deferred payment plan in lieu of full deposit of the amount of a disputed bill to initiate the complaint procedure with the Commission.

122. As appropriate, SDG&E should make the tariff changes found to be reasonable in previous findings in its Financial Division Standard Practice Manual.

123. The record shows that, at times, SDG&E has not made clear to customers with delinquent bills that an installment payment option is available. SDG&E should be ordered to do so.

124. Capacity payments to qualifying facilities should be as shown on Table 1 of Exhibit 103 and for the purpose of QF pricing the IHRs shown on Table 1-12 of Exhibit 74 are fair.

125. The attrition mechanism proposed by the staff and SDG&E for 1985 rates is proper with the exception that the staff proposal for the identification of fixed expenses not subject to attrition should be adopted.

126. Reflecting previous findings, the results of operations under present rates as shown on Table 12 are reasonable.

127. The adopted rate of return of 12.82% coupled with the adopted rate base shown on Table 12 results in an increased revenue requirement over that produced by present rates of $14,315,000.

128. The rates and charges shown in Appendix C, which comport with our previous findings, will produce the additional revenue requirement noted in Finding 128.

129. The increases in rates and charges authorized by this decision are justified, and are just and reasonable.

130. Because the Commission's Rate Case Plan under which this application was processed requires rate changes authorized by this decision to become effective January 1, 1984, the effective date of this decision should be five days from today.

131. Toward Utility Rate Normalization's (TURN) petition filed October 5, 1983 to intervene in this proceeding for the purpose of setting aside submission and reopening the proceeding to consider the appropriate rate treatment of SDG&E's revenue requirement related to SONGS 1 should be denied because the Commission will consider the

matter in OII 83-10-02 in which TURN can participate; however, all costs for the support of SONGS 1 facilities included in this decision should be made subject to refund pending the outcome of OII 83-10-02.

Conclusion of Law

Based on the foregoing findings of fact and under PU Code § 454, this Commission may grant SDG&E authority to increase rates as provided in the following order to enable SDG&E to earn additional annual revenues amounting to $147,315,000.

INTERIM ORDER

IT IS ORDERED that:

1. San Diego Gas & Electric Company (SDG&E) is authorized to file with this Commission the revised rate schedules shown in Appendix C in compliance with General Order Series 96 on or after the effective date of this order. The revised schedules shall apply only to service rendered on or after their effective date, which shall be no sooner than January 1, 1984.

2. The SONGS 1 resleeving expenses referred to in Findings 28, 29, and 30 shall be subject to refund pending the outcome of the Commission's investigation into the reasonableness of Edison's pursuit of litigation against the SONGS 1 contractor for the resleeving project.

3. All costs for the support of SONGS 1 facilities included in this decision shall be subject to refund pending the outcome of the Commission's investigation in OII 83-10-02 of the appropriate rate treatment for SONGS 1.

4. For future rate cases, SDG&E shall provide RD&D estimates in constant year dollars for labor versus nonlabor and other; the future filings and the annual April RD&D report shall be in the format shown in Appendix D of Exhibit 45 and include the information requested by staff on pages 2 and 3 of Exhibit 45 consistent with D.82-12-005.

5. Funds authorized in this decision for conservation, cogeneration, and load management which are unexpended at the end of the rate life of this decision shall be subject to refund.

6. SDG&E may file an advice letter November 1, 1984 for increased rates to offset financial and operational attrition consistent with that authorized in D.93892 as modified by the discussion and findings set forth in this decision.

7. Interest on amounts subject to refund shall be computed by applying the Federal Reserve Board Commercial Paper Rate, three-month Prime, published monthly in Federal Reserve Board Statistical Release G-13 with monthly compounding.

8. The issue of the ratemaking treatment of the Blythe site will be the subject of further hearings to be scheduled in early 1984.

9. Pending resolution of the issue of the Blythe site, SDG&E shall continue the plant in rate base at a rate of return of 10.59%.

10. The Commission policy for conservation, load management, and cogeneration for SDG&E is the one set out in Section 15.1.10 of this decision.

11. SDG&E and the staff shall propose conservation and cost-effectiveness tests which, in as practical a way as possible, can be used to serve the conservation policy adopted by Ordering Paragraph 10.

12. In future proceedings requiring adjustment of SDG&E's rates, the system percentage change method shall be used to make any adjustments except for lighting rates which will not be adjusted until marginal cost studies for lighting services are made.

13. SDG&E and the staff shall cooperatively develop a new small commercial customer time-of-use schedule and an expansion of the agricultural time-of-use schedule and present them no later than July 1, 1984.

14. SDG&E and the staff shall prepare and present marginal cost studies for lighting services in SDG&E's 1986 rate case; the studies shall consider transferring ownership to users of facilities now owned by SDG&E.

15. SDG&E's proposed allocation of the profit on the sale of the Sorrento East property is adopted.

16. SDG&E shall make no proration of lifeline/baseline volumes during periods of changeover.

17. The electricity usages proposed by SDG&E shall be used for baseline allowances.

18. The gas volumes proposed by SDG&E as baseline allowances shall be examined in further hearings to determine compliance with the legislative intent of AB 2443.

19. Implementation of baseline allowances shall be at the time proposed by staff.

20. SDG&E shall review its interruptible and customer generation schedules as proposed by staff and present the results in its 1986 general rate case.

21. Capacity payments to qualifying facilities shall be as shown on Table 1 of Exhibit 103, and, for the purpose of QF pricing, the IERs shown on Table 1-12 of Exhibit 74 are fair.

22. With the modifications recommended by staff incorporated, SDG&E is authorized to establish its proposed Steam Revenue Adjustment Mechanism.

23. Within 60 days from the effective date of this decision, SDG&E shall make advice letter filings which establish provisions in its tariffs that:

a. Require that customers be notified of the reason their service is being terminated; such notice shall be given prior to termination.

b. Allow customers to obtain SDG&E's payment plan option up to, and including, the expiration date of the final notice prior to service termination.

c. Make the 48-hour provision in present Rule 11-A applicable to all customers.

d. Provide a rule similar to WRO's proposed Rule 11.1 in Exhibit 105 which clarifies and emphasizes SDG&E's shutoff procedures for service to seriously ill customers.

e. Allow the initiation of a deferred payment plan in lieu of full deposit of the amount of a disputed bill to initiate a complaint procedure with the Commission.

f. Require that its employees make clear to customers with delinquent bills that an installment payment option is available.

24. SDG&E shall reflect the changes in ordering Paragraph 22 in its Financial Division Standard Practice Manual.

25. TURN's October 5, 1983 petition to intervene in this proceeding is denied.

26. To the extent not authorized by this decision, A.82-12-57 is denied.

This order becomes effective 5 days from today.

Dated December 20, 1983, at San Francisco, California.

LEONARD M. GRIMES, JR.
President
VICTOR CALVO
PRISCILLA C. GREW
DONALD VIAL
WILLIAM T. BAGLEY
Commissioners

I dissent in part.

/s/ PRISCILLA C. GREW
Commissioner

I abstain on portion of the decision concerning small power producers because of reportable financial interest in potential small power producers.

/s/ PRISCILLA C. GREW
Commissioner

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

Joseph E. Bodovitz

Joseph E. Bodovitz, Executive Director

A.82-12-57 ec

APPENDIX A

List of Appearances

Applicant: Jeffrey Lee Guttero, Randall W. Childress, and William L. Reed, Attorneys at Law, for San Diego Gas & Electric Company.

Interested Parties: John W. Witt, City Attorney, by William S. Shaffran and Steven A. McKinley, Deputy City Attorneys, for City of San Diego; Allen R. Crown and Antone S. Bulich, Jr., Attorneys at Law, for California Farm Bureau Federation; Donald M. Clary, Attorney at Law, for Southern California Edison Company; Walters, Bukey & Shelburne, by Diana D. Halpenny, for SCRUB (Schools Committee for Reducing Utility Bills); William L. Knecht, by Philip Presber, Attorney at Law, for California Association of Utility Shareholders; Gary W. Estes, for Home Federal Savings & Loan Association; Biddle & Hamilton, by Richard L. Hamilton, Attorney at Law, for Western Mobilehome Association; Norman Furuta, Attorney at Law, Robert Kittel, and Paul W. Manning, for Department of the Navy; Thomas D. Clarke and Robert M. Loch, Attorneys at Law, for Southern California Gas Company; Virginette Olson, for La Jolla Capri Aire Cooperative Apartments; Jack Templeton, for San Diego Coalition; Nicki Hobson, for Greater San Diego Chamber of Commerce; Jacqueline Valenzuela, Attorney at Law, for Welfare Rights Organization; Steven M. Cohn, Attorney at Law, for California Energy Commission; R & W Consultants, by Paul A. Weir, for Associated General Contractors, Rock Producers Association; H. C. Jay Powell, for Sierra Club; James Hodges and William B. Marcus, for California/Nevada Community Action Association; Carolle Le Monnier, Attorney at Law, for Telacu; Joseph J. Honick, for Insulation Contractors Association; and Michael A. Nagengast and Edward J. Neuner, for themselves.

Commission Staff: James S. Rood and Alvin S. Pak, Attorneys at Law, and Francis S. Ferraro.

APPENDIX B
(Page 1)

TABLE 8-A

SAN DIEGO GAS AND ELECTRIC COMPANY

ELECTRIC DEPARTMENT

SUMMARY OF PRODUCTION EXPENSES

EXCLUDING ECAC

TEST YEAR 1984 (IN $81)

LN NO	ACCT. NO	ITEM	
1		OPERATION	41724.2
2		MAINTENANCE	22308.6
3		MISCELLANEOUS	1123.3
4		SUBTOTAL	65156.1
5		FUEL UNDISTRIBUTED	1513.7
6		FUEL COST-NON ECAC	9.0
7		TOTAL PRODUCTION EXPENSE	66678.8
8		LABOR ADJ.	4276.0
9		NON-LABOR ADJ.	2153.0
10		TOTAL AFTER ADJ. (584)	73107.8

SAN DIEGO GAS AND ELECTRIC COMPANY

ELECTRIC DEPARTMENT

PRODUCTION EXPENSES EXCLUDING ECAC

STEAM POWER PRODUCTION

TEST YEAR 1984 (IN $81)

LN NO	ACCT. NO	ITEM	
		OPERATION	
1	500.00	SUPERVISION & ENGINEERING	2356.4
2	502.00	STEAM EXPENSES	3445.2
3	504.00	STEAM TRANSFERRED	-28.8
4	505.00	ELECTRIC EXPENSES	3664.0
5	506.00	RD & D PROJECTS ($82)	0.0
6	506.00	HEBER BINARY PROJ. ($84)	10600.0
7	506.00	MISC. (NON-RD & D)	1372.4
8	507.00	RENTS	9436.6
9		SUSTOTAL	30845.8
		MAINTENANCE	
10	510.00	SUPERVISION & ENGINEERING	1733.3
11	511.00	STRUCTURES	3783.7
12	512.00	BOILER PLANT	4764.6
13	513.00	ELECTRIC PLANT (TURBINE)	3770.0
14	514.00	MISCELLANEOUS EQUIPMENT	315.7
15		SUBTOTAL	14367.3
16		TOTAL STM. PWR. EXP.	45213.1
17		LABOR ADJ.	2989.3
18		NON-LABOR ADJ.	1123.1
19		TOTAL STM.P.R.EXP.($84)	49325.5

TABLE 8-C

SAN DIEGO GAS AND ELECTRIC COMPANY

ELECTRIC DEPARTMENT

PRODUCTION EXPENSES EXCLUDING ECAC

NUCLEAR POWER PRODUCTION

TEST YEAR 1984 (IN $81)

LN NO	ACCT. NO	ITEM	
		OPERATION	
1	517.00	SUPERVISION & ENGINEERING	2884.1
2	519.00	COOLANTS & WATER	435.3
3	520.00	OPERATION OF REACTOR	879.3
4	523.00	ELECTRIC EXPENSES	65.5
5	524.00	MISCELLANEOUS EXPENSES	2170.6
6	524.00	SLEEVING-SONGS UNIT #1	3769.0
7	525.00	RENTS ($84)	14.5
8		SUBTOTAL	10218.3
		MAINTENANCE	
9	528.00	SUPERVISION & ENGINEERING	2062.0
10	529.00	STRUCTURES	183.6
11	530.00	REACTOR PLANT EQUIPMENT	1487.9
12	531.00	ELECTRIC PLANT	1554.1
13	532.00	MISC NUCLEAR PLANT	183.9
14		SUBTOTAL	5471.5
15		TOTAL NUC. EXPENSE	15689.8
16		LABOR ADJ.	907.4
17		NON-LABOR ADJ.	804.8
18		TOTAL NUC. EXP. ($84)	17402.0

TABLE 8-D

SAN DIEGO GAS AND ELECTRIC COMPANY

ELECTRIC DEPARTMENT

PRODUCTION EXPENSES EXCLUDING ECAC

GAS TURBINE POWER PRODUCTION AND OTHER POWER SUPPLY EXPENSES

TEST YEAR 1984 (IN $81)

LN NO	ACCT. NO	ITEM	
		GAS TURBINE OPERATION	
1	546.00	SUPERVISION & ENGINEERING	89.0
2	548.00	GENERATION	209.4
3	549.00	RD & D PROJECTS ($82)	278.6
4	549.00	MISCELLANEOUS EXPENSES	83.1
5	550.00	RENTS	.0
6		SUBTOTAL	660.1
		GAS TURBINE MAINTENANCE	
7	551.00	SUPERVISION & ENGINEERING	147.1
8	552.00	STRUCTURES	54.5
9	553.00	GENERATING EQUIPMENT	2263.3
10	554.00	MISC PLANT EQUIPMENT	4.9
11		SUBTOTAL	2469.8
		OTHER POWER SUPPLY	
12	556.00	SYSTEM AND LOAD CONTROL	873.3
13	557.00	MISCELLANEOUS EXPENSES	250.0
14		SUBTOTAL	1123.3
15		TOTAL EXPENSES	4253.2
16		LABOR ADJ.	379.3
17		NON-LABOR ADJ.	225.1
18		TOTAL EXPENSES ($84)	4857.6

TABLE 8-E

SAN DIEGO GAS AND ELECTRIC COMPANY

ELECTRIC DEPARTMENT

NON-ECAC FUEL EXPENSES

TEST YEAR 1984 (IN $81)

LN NO	ACCT. NO	ITEM	
		NON-ECAC FUEL HANDLING	
1	501.20	FUEL OIL EXPENSES ($84)	1493.5
2	501.40	FUEL GAS EXPENSES ($84)	12.3
3	547.20	DIESEL FUEL-GAS TURB. ($84)	7.9
4	547.40	GAS FUEL-GAS TURBINE ($84)	.0
5		SUBTOTAL	1513.7
		NON-ECAC FUEL COST	
6	501.10	FUEL OIL ($84)	2.2
7	501.30	FUEL GAS ($84)	3.8
8	518.00	NUCLEAR FUEL ($84)	.0
9	547.10	DIESEL FUEL-GAS TURB. ($84)	.0
10	547.30	GAS FUEL-GAS TURBINES ($84)	.4
11	555.00	PURCHASED POWER CAP. ($84)	1.0
12	555.00	PURCHASED POWER ($84)	1.6
13	557.30	NARCO FUEL SERVICE AGREE.	.0
14		SUBTOTAL	9.0
15		TOTAL NON-ECAC FUEL EXP.	1522.7
16		LABOR ADJ.	.0
17		NON-LABOR ADJ.	.0
18		TOT. NON-ECAC FUEL EXP. ($84)	1522.7

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APPENDIX B
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TABLE 9-A

SAN DIEGO GAS AND ELECTRIC COMPANY

ELECTRIC DEPARTMENT

TRANSMISSION EXPENSES

TEST YEAR 1984 (IN $81)

LN NO	ACCT. NO	ITEM	
		OPERATION	
1	560.00	SUPERVISION & ENGINEERING	559.3
2	561.00	LOAD DISPATCHING	1297.2
3	562.00	STATION EXPENSES	459.6
4	563.00	OVERHEAD LINE EXPENSES	166.3
5	564.00	UNDERGROUND LINE EXPENSES	0.5
6	565.00	TRANSMISSION BY OTHERS ($84)	13426.6
7	566.00	MISCELLANEOUS EXPENSES	84.5
8	566.00	RD & D PROJ. ($82)	1.8
9	567.00	RENTS ($84)	176.1
10		TOTAL OPERATION EXPENSES	16171.9
		MAINTENANCE	
11	568.00	SUPERVISION & ENGINEERING	57.1
12	569.00	STRUCTURES	1.5
13	570.00	STATION EQUIPMENT	998.0
14	571.00	OVERHEAD LINES	1661.4
15	572.00	UNDERGROUND LINES	17.9
16	573.00	MISC. TRANSMISSION PLANT	1.7
17		TOTAL MAINTENANCE EXPENSES	2737.6
18		TOTAL TRANS. EXPENSE	18909.5
19		LABOR ADJ.	729.3
20		NON-LABOR ADJ.	175.0
21		TOTAL TRANS. EXP. ($84)	19813.8

SAN DIEGO GAS AND ELECTRIC COMPANY

ELECTRIC DEPARTMENT

DISTRIBUTION EXPENSES

TEST YEAR 1984 (IN $81)

LN NO	ACCT. NO	ITEM	
		OPERATION	
1	580.00	SUPVERVISION & ENGINEERING	1477.6
2	582.00	STATION EXPENSES	1073.3
3	583.00	OVERHEAD LINE EXPENSES	1990.9
4	584.00	UNDERGROUND LINE EXPENSES	844.9
5	585.00	STREET LIGHT EXPENSES	236.7
6	586.00	METER EXPENSES	1839.9
7	587.00	CUSTOMER INST. EXPENSES	1278.0
8	588.00	MISC DISTR. EXPENSES	5180.5
9	588.00	RD & D PROJ. ($82)	107.0
10	589.00	RENTS ($84)	32.6
11		TOTAL OPERATION EXPENSE	14061.4
		MAINTENANCE	
12	590.00	SUPVERVISION & ENGINEERING	429.9
13	591.00	STRUCTURES	38.9
14	592.00	STATION EQUIP.	787.1
15	593.00	OVERHEAD LINES	10307.4
16	594.00	UNDERGROUND LINES	3121.9
17	595.00	LINE TRANSFORMERS	612.0
18	596.00	ST. LIGHT. & SIGNAL SYS.	154.1
19	597.00	METERS	599.0
20	598.00	MISC DIST PLANT	30.8
21		TOTAL MAINTENANCE EXPENSE	16080.6
22		TOTAL DISTRIB. EXPENSE	30142.0
23		LABOR ADJ.	3719.0
24		NON-LABOR ADJ.	1232.0
25		TOTAL DISTRIB. EXP. ($84)	35093.0

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TABLE 11-A

APPENDIX B
(Page 8)

SAN DIEGO GAS AND ELECTRIC COMPANY

ELECTRIC DEPARTMENT

CUSTOMER ACCOUNTS EXPENSES

TEST YEAR 1984 (IN $M)

LN NO	ACCT. NO	ITEM	
1	901.00	SUPERVISION	244.0
2	902.00	METER READING	2094.0
		CUSTOMER RECORDS AND COLL.	
3	903.10	CUSTOMER SERVICE	3811.0
4	903.20	CREDIT MANAGEMENT	164.0
5	903.30	COLLECTIONS	1331.0
6	903.40	CUSTOMER PAYMENTS	484.0
7	903.50	BILLING & BOOKKEEPING	806.0
8	903.60	DATA PROCESSING	1457.0
9	903.70	POSTAGE ($84)	1245.0
10		TOTAL CUST. REC. AND COLL.	9298.0
11	904.00	UNCOLLECTIBLE ACCT. ($84)	1263.2
12	905.00	MISC. CUST. ACCT. EXP.	30.0
13		TOTAL CUST. ACCTS. EXP.	12929.2
14		LABOR ADJ.	1595.0
15		NON-LABOR ADJ.	415.0
16		TOTAL CUST.ACCT. EXP.($84)	14939.2

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TABLE 12-A

APPENDIX B
(Page 9)

SAN DIEGO GAS AND ELECTRIC COMPANY

CUSTOMER SERVICE AND INFORMATIONAL EXPENSES

TEST YEAR 1984 (IN $82)

ACCT. NO	ITEM				
	TOTAL CUST.SER.&INFO. EXP.	10422.7	15577.[illegible]	5154.4	49.5
	LABOR ADJ.	[illegible]	6352.9	149.1	30.[illegible]
	NON-LABOR ADJ.	234.6	378.1	143.5	61.[illegible]
	UNSPENT FUNDS	-2693.0	[illegible]	2693.0	100.0
	TOTAL CUST.SER.&INFO.($84)	8452.1	16591.[illegible]	8140.0	96.3

TABLE 13-A

SAN DIEGO GAS AND ELECTRIC COMPANY

ELECTRIC DEPARTMENT

ADMINISTRATIVE AND GENERAL EXPENSES

TEST YEAR 1984 (IN $81)

LN. NO	ACCT. NO	ITEM	
1			
2	920.00	ADMIN. & GEN. SALARIES	13915.9
3	921.00	OFFICE SUPPLIES & EXPENSES	6801.8
4	922.00	A & G TRANS. CREDIT	-6834.0
5	923.00	OUTSIDE SERVICES EMPLOYED	962.9
6	924.00	PROPERTY INSURANCE($84)	2702.9
7	925.00	INJURIES & DAMAGES($84)	2066.1
8	926.00	EMPLOY. PENSION & BENEFITS	18825.6
9	927.00	FRANCHISE REQUIREMENTS ($84	10454.8
10	928.00	REG. COMM. EXPENSES	419.8
11	929.00	DUPLICATE CHARGES-CREDIT($8	-2055.8
12	930.00	MISC. GENERAL EXPENSE	1673.2
13	930.00	MISC. RD&D (RRD) ($82)	2769.8
14	930.00	RD&D(LD.MGMT.&CONS.)($82)	763.5
15	930.00	BANK FEES($84)	312.0
16	931.00	RENTS	974.6
17	932.00	MAINT. GEN. PLANT($84)	1902.3
18		TOTAL A&G EXPENSE	55655.4
19		LABOR ADJ.	4340.0
20		NON-LABOR ADJ.	1132.1
21		A&G EXPENSE ($84)	61127.5

TABLE 14-A

SAN DIEGO G & E - ELECTRIC DEPARTMENT
SUMMARY OF TAX EXPENSES
TEST YEAR 1984

LN NO	ACCT. NO	ITEM	
1		AD VALOREM TAXES	14944.2
		OTHER TAXES	
2		FEDERAL INSURANCE ACT (FICA	3634.0
3		FEDERAL UNEMPLOYMENT (FUI)	105.3
4		CALIF UNEMPLOYMENT (SUI)	223.7
5		MISCELLANEOUS	3.7
6		SUBTOTAL	3966.7
7.		TOTAL NON-INCOME TAXES AT ADOPTED RATES	18910.9
		-- -------- -------	
8		CALIF CORP FRANCHISE TAX	17501.7
9		FEDERAL CORP INCOME TAX	77199.9
10		SUBTOTAL-INCOME TAXES	94701.6
11		TOTAL TAXES AT ADOPTED RATES	103612.5

TABLE 14-C

SAN DIEGO GAS AND ELECTRIC COMPANY

CALIFORNIA CORPORATE FRANCHISE TAX DEDUCTIONS

TEST YEAR 1984

LN NO	ACCT. NO	ITEM	
1		TAX DEPRECIATION	55686.0
2		AMORTIZATION	1362.7
3		INTEREST CHARGES	49581.0
4		BENEFITS CAPITALIZED	7500.0
5		AD-VALOREM TAXES CAP.	224.0
6		REMOVAL COSTS	3530.0
7		REPAIR ALLOWANCE	8307.0
8		USE TAX	1151.0
9		TAXABLE CIAC	-1993.0
10		FISCAL/CALENDAR ADJ.	391.0
11		OTHER DEDUCTIONS	-8279.0

TABLE 14-D

SAN DIEGO GAS AND ELECTRIC COMPANY

FEDERAL INCOME TAX DEDUCTIONS

TEST YEAR 1984

LN NO	ACCT. NO	ITEM	
1		TAX DEPRECIATION	59539.0
2		AMORTIZATION	1362.7
3		INTEREST CHARGES	
4		CURRENT	49561.0
5		TEFRA	.0
6		BENEFITS CAPITALIZED	7500.0
7		AD VALOREM TAXES CAP.	
8		CURRENT	224.0
9		TEFRA	.0
10		REMOVAL COSTS	.0
11		PREFERRED DIVIDEND CREDIT	533.0
12		USE TAX	1151.0
13		TAXABLE CIAC	-1993.0
14		RESEARCH & DEVELOPMENT	.0
15		FISCAL/CALENDAR ADJ.	391.0
16		OTHER DEDUCTIONS	-8279.0
17		CREDITS	
18			
19		DEFERRED TAX DEPREC.	58.0
20		INVESTMENT TAX CR. NORM.	1500.0
21		GRADUATED RATE BENEFIT	18.0
22		RESEARCH & EXPERIMENT CR.	463.0
23		DEFERRED TAXES TO DEDUCT	
24		FROM RATE BASE	11089.0

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TABLE 15-A

SAN DIEGO GAS AND ELECTRIC COMPANY

ELECTRIC DEPARTMENT

UTILITY PLANT IN SERVICE

1983

LN NO	ACCT. NO	ITEM	
1		ELECTRIC DEPARTMENT	
2		---------------------	
3		BEGINNING-OF-YEAR BALANCE	1317585
4		ADDITIONS	141164
5		RETIREMENTS & ADJUSTMENTS	-7247
6		END-OF-YEAR BALANCE	1451502
7		COMMON PLANT ALLOCATED	
8		------------------------	
9		BEGINNING-OF-YEAR BALANCE	21228
10		ADDITIONS	1011
11		RETIREMENTS	-170
12		END-OF-YEAR BALANCE	22069

TABLE 15-A

SAN DIEGO GAS AND ELECTRIC COMPANY

ELECTRIC DEPARTMENT

UTILITY PLANT IN SERVICE

TEST YEAR 1984

LN NO	ACCT. NO	ITEM	
1		ELECTRIC DEPARTMENT	
2		-------------------	
3		BEGINNING-OF-YEAR BALANCE	1451502
4		ADDITIONS	141178
5		RETIREMENTS & ADJUSTMENTS	-7888
6		END-OF-YEAR BALANCE	1584792
7		COMMON PLANT ALLOCATED	
8		----------------------	
9		BEGINNING-OF-YEAR BALANCE	22069
10		ADDITIONS	2907
11		RETIREMENTS	-170
12		END-OF-YEAR BALANCE	24806
13		AVG. UTIL. PLANT IN SERVICE	
14		---------------------------	
15		ELECTRIC PLANT	1494428
16		COMMON ALLOCATED PLANT	23261
17		TOTAL AVERAGE PLANT	1517709

TABLE 16-E

SAN DIEGO GAS AND ELECTRIC COMPANY

ELECTRIC DEPARTMENT

DEPRECIATION AND AMORTIZATION EXPENSE

TEST YEAR 1984

LN. NO	ACCT. NO	ITEM	
1		DEPRECIATION & AMORT. EXP.	66154.6
2		TOTAL DEPR. & AMORT. EXP.	66154.6

TABLE 16-F

SAN DIEGO GAS AND ELECTRIC COMPANY

ELECTRIC DEPARTMENT

DEPRECIATION AND AMORTIZATION RESERVE

TEST YEAR 1984

LN NO	ACCT. NO	ITEM	
1		DEPRECIATION & AMORTIZATION RESERVE - AS OF 12/31/84	492844.0
2		TOTAL DEP. & AMORT. RESERVE	492844.0

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TABLE 17-A

APPENDIX B
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SAN DIEGO G & E - ELECTRIC DEPARTMENT

WEIGHTED AVERAGE DEPRECIATED RATE BASE

TEST YEAR 1984

LN. NO.	ACCT.	ITEM	
		BEG. BALANCE- FIXED CAPITAL	
1		PLANT IN SERVICE	1473571
2		PLANT HELD FOR FUTURE USE	13716
3		RESEARCH AND DEVELOPMENT	0
4		SUBTOTAL	1487287
5		NET PLANT ADDITIONS	41306
6		TOTAL FIXED CAPITAL	1528593
7		CUST. ADVANCE FOR CONSTR.	-23148
8		WORKING CAPITAL	
9		FUEL IN STORAGE	12424
10		MATERIALS & SUPPLIES	27900
11		WORKING CASH	22015
12		TOTAL WORKING CAPITAL	62339
13		TOTAL BEFORE RESERVES	1567784
14		RESERVES	
15		DEFERRED INCOME TAXES	10830
16		DEPRECIATION	458306
17		AMORTIZATION & OTHER	15078
18		TOTAL RESERVES	484214
19		TOTAL RATE BASE	1083570

DEVELOPMENT OF AVERAGE LAG IN PAYMENT OF EXPENSES

	$ 1000 A	AVG DAY LAG B	$ 1000 C=A X B
FEDERAL INCOME TAX	81452.00	83.09	6767846.69
STATE INCOME TAX	18483.30	73.34	1355565.20
FRANCHISE REQUIREMENTS	24272.70	170.66	4142378.97
FUEL OIL	174635.00	15.92	2780189.19
PURCHASED GAS	298806.00	37.96	11342751.63
NUCLEAR FUEL	7782.00	.00	.00
COMPANY LABOR	85197.00	13.54	1153567.38
PURCHASED POWER	200864.00	36.45	7321492.75
GOODS & SERVICES	78376.00	33.91	2657730.13
EMPLOYEE BENEFITS	16713.20	-1.43	-23899.88
DEFERRED TAX	6787.00	.00	.00
DEFERRED TAX ADJ.	-6787.00	83.09	-563931.83
FEDERAL UNEMPLOYMENT TAX	105.30	72.04	7585.81
FICA TAX	3634.00	6.94	25219.96
AD VALOREM	14736.80	47.01	692776.97
DEPRECIATION & AMORTIZATION	66154.60	.00	.00
MATERIALS FROM STOREROOM	1591.00	.00	.00
S.U.I. & MISC. TAXES	227.40	76.04	17291.50
ENCINA 5 LEASE EXPENSES	9295.00	92.50	859787.50
MISC. RES.	4769.00	.00	.00
TOTAL	1087096.27		36536350.50

EXP LAG DAYS= C/A = 33.45

REVENUE LAG DAYS = 42.77

ADJUSTMENT TO RATE BASE 21801.49

SAN DIEGO GAS AND ELECTRIC COMPANY

GAS DEPARTMENT

GAS SUPPLY EXPENSES

TEST YEAR 1984 ($81)

LN NO	ACCT. NO	ITEM	
1	807.00	PURCHASED GAS EXPENSES	91.3
2	810.00	GAS USED-COMPRESSOR FUEL	-783.2
3	812.00	GAS USED-OTHER OPERATIONS	-36.2
4		TOTAL GAS SUPPLY EXPENSE	-728.1
5		LABOR ADJ.	14.7
6		NON-LABOR ADJ.	-588.5
7.		TOTAL GAS SUPPLY EXP. ($84)	-1301.9

SAN DIEGO GAS AND ELECTRIC COMPANY

GAS DEPARTMENT

STORAGE EXPENSES

TEST YEAR 1984 ($81)

LN NO	ACCT. NO	ITEM	
1		OPERATION	
2		LOCAL STORAGE EXPENSES	
3	840.00	OPER., SUPV. & ENG.	245.6
4	841.00	OPER. LABOR & EXP.	1171.4
5		TOTAL GAS OPERATION EXP.	1417.0
6		MAINTENANCE	
7		LOCAL STORAGE PLANT	
8	843.00	SUPV. & ENGR.	396.8
9		TOTAL GAS MAINT. EXPENSE	396.8
10		TOTAL GAS STORAGE EXPENSE	1813.8
11		LABOR ADJ.	173.0
12		NON-LABOR ADJ.	368.7
13		TOTAL STORAGE EXPENSES ($84	2355.5

TABLE 10-A

SAN DIEGO GAS AND ELECTRIC COMPANY

GAS DEPARTMENT

TRANSMISSION EXPENSES

TEST YEAR 1984 ($M)

LN NO	ACCT. NO	ITEM	
1		OPERATION	
2	850.00	SUPV. & ENGR.	363.6
3	851.00	SYS. CONTR. & LOAD DISPATCH	179.4
4	852.00	COMMUNICATION SYSTEM EXP	11.3
5	853.00	COMP. STA. LABOR & EXP.	224.1
6	854.00	GAS FOR COMP. STA. FUEL	451.7
7	855.00	OTHER FUEL POWER COMP STA.	49.4
8	856.00	MAINS EXPENSE	236.5
9	857.00	MEAS.& REG. STA. EXP.	73.2
10	859.00	OTHER EXPENSES	52.5
11	860.00	RENTS	.2
12		TOTAL OPER. EXPENSE	1641.9
13		MAINTENANCE	
14	861.00	SUPV. & ENGR	68.2
15	862.00	STRUCT. & IMPROVE.	12.9
16	863.00	MAINS	73.2
17	864.00	COMP. STA. EQUIP.	184.0
18	865.00	MEAS.& REG. STA. EQUIP	18.1
19	867.00	OTHER EQUIP.	.1
20		TOTAL MAINT. EXPENSE	356.5
21		TOTAL TRANSMISSION EXPENSE	1998.4
22		LABOR ADJ.	211.4
23		NON-LABOR ADJ.	448.9
24		TOTAL TRANS. EXP. ($84)	2658.7

TABLE II-A

SAN DIEGO GAS AND ELECTRIC COMPANY

GAS DEPARTMENT

DISTRIBUTION EXPENSES

TEST YEAR 1984 ($81)

LN NO	ACCT. NO	ITEM	
1		OPERATION	
2	870.00	SUPV. & ENGR.	1243.5
3	871.00	DISTR. LOAD DISPATCH.	95.7
4	874.00	MAINS & SERV. EXP.	1056.3
5	875.00	MEAS.& REG.STA.EXP.-GENERAL	118.3
6	878.00	METER AND HOUSE REG. EXP.	2024.8
7	879.00	CUSTOMER INSTALL. EXP.	3282.0
8	880.00	OTHER EXPENSE	1125.6
9	881.00	RENTS	2.6
10		TOTAL OPERATION EXPENSES	8949.0
11		MAINTENANCE	
12	885.00	SUPV.& ENGR.	159.6
13	886.00	STRUC. & IMPROVE.	.0
14	887.00	MAINS-LEAK CLAMPS	1228.7
15	889.00	MEAS.&REG.STA.EQUIP.GEN.	38.9
16	892.00	SERVICES	398.2
17	893.00	METERS	1037.7
18	894.00	OTHER EQUIP.	7.5
19		TOTAL MAINTENANCE EXPENSES	2870.6
20		TOTAL DISTRIB. EXPENSES	11819.6
21		LABOR ADJ.	1808.7
22		NON-LABOR ADJ.	280.0
23		TOTAL DISTRIB. EXPENSES ($8	13908.3

TABLE 12-A

SAN DIEGO GAS AND ELECTRIC COMPANY

GAS DEPARTMENT

CUSTOMER ACCOUNTS EXPENSES

TEST YEAR 1984 ($81)

LN NO	ACCT. NO	ITEM	
1	901.00	SUPERVISION	141.0
2	902.00	METER READING	1208.0
3		CUSTOMER RECORDS AND COL.	
4	903.10	CUSTOMER SERVICE	2197.0
5	903.20	CREDIT MANAGEMENT	94.0
6	903.30	COLLECTIONS	768.0
7	903.40	CUSTOMER PAYMENTS	279.0
8	903.50	BILLING & BOOKKEEPING	465.0
9	903.60	DATA PROCESSING	858.0
10	903.70	POSTAGE ($84)	701.0
11		TOTAL CUST. REC. AND COLL.	5362.0
12	904.00	UNCOLLECTIBLE ACCT. ($84)	216.5
13	905.00	MISC. CUST. ACCT. EXP.	18.0
14		TOTAL CUST. ACCTS. EXPENCE	6945.5
15		LABOR ADJ.	920.0
16		NON-LABOR ADJ.	239.0
17		TOT. CUST. ACCT. EXP.($84)	8104.5

TABLE 13-A

SAN DIEGO GAS AND ELECTRIC COMPANY

CUSTOMER SERVICE AND INFORMATIONAL EXPENSES

TEST-YEAR 1984 ($82)

LN NO	ACCT. NO	ITEM	
5			
6		TOT. CUST.SER.&INFO.($82)	9197.7
7		LABOR ADJ.	248.3
8		NON-LABOR ADJ.	245.8
9		UNSPENT FUNDS	-2342.0
10		TOT. CUST.SER.&INFO. ($84)	7349.8

A.82-12-57 /ALJ/jn TABLE 14-A APPENDIX B
(Page 26)

SAN DIEGO GAS AND ELECTRIC COMPANY

TEST YEAR 1984 ($81)

LN NO	ACCT. NO	ITEM	
1			
2	920.00	ADMINISTA.& GENER.SALARIES	4656.1
3	921.00	OFFICE SUPPLIES & EXPENSES	2188.0
4	922.00	ADM. EXP. TRANSF.	-2237.2
5	923.00	OUTSIDE SERV.EMPLOY.	304.4
6	924.00	PROPERTY INSURANCE($84)	81.7
7	925.00	INJURIES & DAMAGES($84)	692.7
8	926.00	EMPLOY. PENSION & BENEFITS	6109.6
9	927.00	FRANCHISE REQUIREMENTS($84)	2164.7
10	928.00	REGULATORY COMM. EXPENSES	132.7
11	930.00	MISCELLANEOUS GENERAL EXP.	668.4
12	930.00	MISC. RD&D (RRD)($82)	9.7
13	930.00	RD&D (LD.MGMT.&CONS)($82)	
14	930.00	BANK FEES ($84)	99.0
15	931.00	RENTS	337.6
16	932.00	MAINT.OF GEN. PLANT($84)	602.2
17		TOTAL A&G EXPENSES	15809.6
18		LABOR ADJ.	1414.3
19		NON-LABOR ADJ.	366.0
20		TOTAL A&G EXP. ($84)	17589.9

TABLE 15-A

SAN DIEGO G & E - GAS DEPARTMENT
SUMMARY OF TAXES

TEST YEAR 1984 (SSI)

LN NO	ACCT. NO	ITEM	
1		AD VALOREM TAXES	2164.3
		OTHER TAXES	
2		FED INSURANCE ACT (FICA)	1140.5
3		FEDERAL UNEMPLOYMENT (FUI)	33.0
4		CALIF UNEMPLOYMENT (SUI)	70.2
5		MISCELLANEOUS	1.3
6		SUBTOTAL OTHER TAXES	1245.0
7.		TOTAL NON-INCOME TAXES	3409.3
		AT ADOPTED RATES	
8		CALIF. CORP FRANCHISE TAX	3294.6
9		FEDERAL CORP INCOME TAX	13636.2
10		SUBTOTAL INCOME TAXES	16930.8
11		TOTAL TAXES AT ADOPTED RATES	20340.1

TABLE 15-C

SAN DIEGO GAS AND ELECTRIC COMPANY

SDG&E GAS DEPARTMENT

CALIFORNIA CORPORATE FRANCHISE TAX DEDUCTIONS

TEST YEAR 1984

LN NO	ACCT. NO	ITEM	
1		TAX DEPRECIATION	9046.0
2		AMORTIZATION	108.0
3		INTEREST CHARGES	8397.0
4		BENEFITS CAPITALIZED	2403.0
5		AD-VALOREM TAXES CAP.	17.0
6		REMOVAL COSTS	438.0
7		REPAIR ALLOWANCE	472.0
8		USE TAX	363.0
9		TAXABLE CIAC	-383.0
10		FISCAL/CALENDAR ADJ.	46.0
11		OTHER DEDUCTIONS	-1656.0

SAN DIEGO GAS AND ELECTRIC COMPANY

[illegible]

FEDERAL INCOME TAX CALCULATIONS

TEST YEAR 1984

LN NO	ACCT. NO	ITEM	
1		TAX DEPRECIATION	[illegible]
2		AMORTIZATION	[illegible]
3		INTEREST CHARGES	
4		CURRENT	[illegible]
5		TEFRA	[illegible]
6		BENEFITS CAPITALIZED	[illegible]
7		AD VALOREM TAXES, CAP.	
8		CURRENT	17.0
9		TEFRA	[illegible]
10		REMOVAL COSTS	[illegible]
11		PREFERRED DIVIDEND CREDIT	[illegible]
12		USE TAX	363.0
13		TAXABLE CIAC	-383.0
14		FISCAL/CALENDAR ADJ.	46.0
15		OTHER DEDUCTIONS	-1656.0
16		CREDITS	
17			.0
18		DEFERRED TAX DEPREC.	12.0
19		INVEST. TAX CREDIT NORM.	200.0
20		GRADUATED RATE BENEFIT	2.0
21		RESEARCH & EXPERIMENT CR.	.0
22		DEFERRED TAXES TO DEDUCT	
23		FROM RATE BASE	2031.0

TABLE 16-A

SAN DIEGO GAS AND ELECTRIC COMPANY

UTILITY PLANT IN SERVICE

1983

LN NO	ACCT. NO	ITEM	
1		GAS DEPARTMENT	
2		--------------	
3		BEGINNING-OF-YEAR BALANCE	278464.0
4		ADDITIONS	18116.0
5		RETIREMENTS	-628.0
6		AUTO & P.O.E. ADJ.	-68.0
7		END-OF-YEAR BALANCE	295884.0
8		COMMON PLANT ALLOCATED	
9		----------------------	
10		BEGINNING-OF-YEAR BALANCE	8009.0
11		ADDITIONS	382.0
12		RETIREMENTS	-64.0
13		END-OF-YEAR BALANCE	8327.0

TABLE 16-E

SAN DIEGO GAS AND ELECTRIC COMPANY

STAFF GAS DEPARTMENT

UTILITY PLANT IN SERVICE

TEST YEAR 1984

LN NO	ACCT. NO	ITEM	
1		GAS DEPARTMENT	
2		--------------	
3		BEGINNING-OF-YEAR BALANCE	295884.0
4		ADDITIONS	17676.0
5		RETIREMENTS	-642.0
6		AUTO & P.O.E. ADJ.	-68.0
7		END-OF-YEAR BALANCE	312850.0
8		COMMON PLANT ALLOCATED	
9		----------------------	
10		BEGINNING-OF-YEAR BALANCE	8327.0
11		ADDITIONS	1097.0
12		RETIREMENTS	-64.0
13		END-OF-YEAR BALANCE	9360.0
14		AVG. UTIL. PLANT IN SERVICE	
15		---------------------------	
16		GAS PLANT	304152.7
17		COMMON PLANT ALLOCATED	8783.1
18		TOTAL AVERAGE PLANT	312935.8

TABLE 17-E

SAN DIEGO GAS AND ELECTRIC COMPANY

GAS DEPARTMENT

DEPRECIATION AND AMORTIZATION EXPENSE

TEST YEAR 1984

LN NO	ACCT. NO	ITEM	
1		DEPRECIATION & AMORT. EXP.	13354.4
2		TOTAL DEPR. & AMORT. EXP.	13354.4

TABLE 17-F

SAN DIEGO GAS AND ELECTRIC COMPANY

GAS DEPARTMENT

DEPRECIATION AND AMORTIZATION RESERVE

TEST YEAR 1984

LN NO	ACCT. NO	ITEM	
1		DEPRECIATION & AMORTIZATION RESERVE - AS OF 12/31/84	135464.8
2		TOTAL DEP. & AMORT. RESERVE	135464.8

TABLE 18-A

SAN DIEGO G & E - GAS DEPARTMENT

WEIGHTED AVERAGE DEPRECIATED RATE BASE

TEST YEAR 1984

LN NO	ACCT. NO	ITEM	
		BEG. BALANCE- FIXED CAPITAL	
1		PLANT IN SERVICE	304210
2		PLANT HELD FOR FUTURE USE	45
3		RESEARCH AND DEVELOPMENT	0
4		SUBTOTAL	304255
5		NET PLANT ADDITIONS	8726
6		TOTAL FIXED CAPITAL	312981
7		CUST. ADVANCES FOR CONSTR.	-9620
8		WORKING CAPITAL	
9		GAS IN STORAGE	3927
10		MATERIALS & SUPPLIES	2801
11		WORKING CASH	2401
12		TOTAL WORKING CAPITAL	9129
13		TOTAL BEFORE RESERVES	312490
14		RESERVES	
15		DEFERRED INCOME TAXES	2031
16		DEPRECIATION	128379
17		AMORTIZATION & OTHER	461
18		TOTAL RESERVES	130871
19		TOTAL RATE BASE	181619

SAN DIEGO G & E - GAS DEPARTMENT

DEVELOPMENT OF AVERAGE LAG IN PAYMENT OF EXPENSES

	$ 1000 A	AVG DAY LAG B	$ 1[illegible] C=A X B
FEDERAL INCOME TAX	13638.20	83.09	1133196.03
STATE INCOME TAX	3295.10	73.34	241662.63
FRANCHISE REQUIREMENTS	6955.80	181.71	1263938.41
PURCHASED GAS	196011.00	37.96	7440577.56
AD VALOREM TAX	2164.30	47.01	101743.74
COMPANY LABOR	26392.00	13.54	357347.68
GOODS & SERVICES	15815.00	33.91	536286.64
EMPLOYEE BENEFITS	5424.00	-1.43	-7756.32
DEFERRED TAX	586.00	.00	.00
DEFERRED TAX ADJ.	-586.00	83.09	-48690.74
FEDERAL UNEMPLOYMENT TAX	33.00	72.04	2377.32
FICA TAX	1140.50	6.94	791[illegible]7
DEPRECIATION & AMORT.	13354.40	.00	.00
MATERIALS FROM STOREROOM	221.00	.00	.00
S.U.I. & MISC. TAX	71.50	76.04	5436.86
MISC. RES.	774.40	.00	.00
TOTAL	285290.20		11034036.63

EXP LAG DAYS= C/A = 38.68

REVENUE LAG DAYS = 42.77

ADJUSTMENT TO RATE BASE= 3196.81

(END OF APPENDIX B)

APPENDIX C

SDG&E GAS RATES

Gas rates are shown in the companion decision issued today in A.83-09-58.

Staff's Conservation and Load Management Program Recommendations

Witness Amaroli

"Stay the Course" by maintaining approximately the current 1983 level of overall program funding, allowing for changes in individual measures activity as recommended by other witnesses in this proceeding.

The Demonstration Solar Financing Program should terminate as scheduled and already announced to the industry and the public. Only those eligible systems having passed inspection on or before the close of the business day on January 13, 1984, and for which applications for rebates were postmarked on or before September 15, 1983, shall be allowed rebates. No new activity should be conducted after that later date.

Natural gas weatherization low interest loan programs should sunset on December 31, 1986. SDG&E should be directed by the Commission's decision in this proceeding to give clear notice to the weatherization contractors in its service area of the sunset date.

Natural gas direct weatherization, cash back and 50/50 programs primarily oriented to low income persons and renters, should be examined for continued potentials or scheduled termination at the end of 1986 in SDG&E's next general rate proceeding.

We should stop relitigating the propriety of each conservation activity at each rate proceeding and concentrate on efficient, effective, implementation of proven programs.

We should establish clear funding limits for electric energy conservation programs based on guideline cost levels of 1 mil per kWh saved by the overall program effort over the useful life of the hardware or activities involved.

The Conservation Voltage Regulation Program should be continued indefinitely until completion. Then the voltage surveillance part of the program should be continued permanently as part of the utility's operation.

Other natural gas conservation programs should be maintained at the current level of activity for at least the next two years.

One key criteria for evaluating conservation programs should be the net effect of the programs on average customer bills provided that broad customer participation is sought to minimize equity impacts.

Load management program activities should be narrowed to fewer programs which are better planned and carried out with greater attention by SDG&E.

Load management activities should focus on expanding interruptible rate options as these activities generally offer the most reliable load management opportunities.

Load management activities should include opportunities and incentives for fuel conversion from electric use to natural gas or solar wherever possible and cost-effective. Simple examples are water heating, cooking and clothes drying in the residential sector.

Modern and inexpensive load management metering and other equipment should be developed rapidly. Programs to do this should be supported by utility management.

Load management programs should effectively control load at the time of SDG&E's peak demand. Load management programs should not include activities which constitute special rate options to reward customers who have already shifted their use patterns or who never used electric energy on-peak. Neither should load management programs include rate options designated to make life easier or more comfortable in climate extremes or to reduce rate burdens for any special class of customer.

It appears that SDG&E will have adequate electrical capacity margins for the next five to ten years, therefore there is no urgency for this Commission to expand SDG&E's load management activities beyond the funding level that staff has recommended for 1984 and 1985. SDG&E should prove that the load management programs it implements during this period are cost-effective, practical for expansion, and worthwhile to mitigate (offset) the need of significant capacity additions in the future before undertaking to expand these activities in test year 1986.

APPENDIX D
Page 3

Very careful and accurate analysis of load management program experimentation and performance should be required of SDG&E during 1984 and 1985 to prove program cost-effectiveness and reliability for development of 1986 program commitments.

Witness Danforth

The $22 million program package proposed by ECB witness Barnhardt should be adopted.

Programs should be designed and considered in the next general rate case which service ratepayer sectors which are less able to participate in current programs.

As weatherization programs mature, electric conservation programs should be emphasized in the residential sector owing to SDG&E's high electric rates.

SDG&E should be ordered to prepare a detailed technical assessment of conservation measures that can be implemented in their service area after weatherization programs mature to lower customer bills.

Low cost or no cost conservation measures such as the pilot light turnoff, "pull-the-plug", and "one warm room" should be promoted extensively to maximize the welfare of the customer.

Maximum loan amounts granted in weatherization programs should be based on average contractor prices encountered in the PG&E service area (Table CT-7).

(END OF APPENDIX D)

APPENDIX E
Page 1

GLOSSARY

A.	Application
AEI	Applied Energy Incorporated
AFUDC	Allowance for Funds Used During Construction
AGA	American Gas Association
ALJ	Administrative Law Judge
APS	Arizona Public Service
AT&T	The American Telephone and Telegraph Company
Becker	Becker Large Plans
BOY	Beginning of Year
C.	Case
CAM	Consolidated Adjustment Mechanism
CAUS	California Association of Utility Shareholders
CEC	California Energy Commission
company	San Diego Gas & Electric Company
CPI	Consumer Price Index
CPI-U	Consumer Price Index - All Urban
CWIP	Construction Work in Progress
CVR	Conservation Voltage Regulation
D.	Decision
DFIS	Distribution Facilities Information System
DRI	Data Resources, Inc.
DWA	Direct Weatherization Assistance
ECAC	Energy Cost Adjustment Clause
Edison	Southern California Edison Company
EEI	Edison Electric Institute
EPD	Equal Percentage of the Difference
EPRI	Electric Power Research Institute
ERAM	Electric Revenue Adjustment Mechanism
FEA	Federal Executive Agencies of the United States

APPENDIX E
Page 2

GLOSSARY

FERC	Federal Energy Regulatory Commission
FUA	Power Plant and Industrial Fuel Use Act of 1978
GNP	Gross National Product
Heber	Heber Binary Project
ICA	Insulation Contractors Association
IEP	Independent Energy Producers
IDB	Industrial Development Bonds
IRP	Intermediate Range Planning
IRS	Internal Revenue Service
kW	Kilowatt
kWh	Kilowatt-hours
MPPI	Modified Producer Price Index
OII	Order Instituting Investigation
PACMAC	Policy Adjusted Class Marginal Cost
PGA	Purchased Gas Adjustment Clause
PG&E	Pacific Gas and Electric Company
PHFU	Plant Held for Future Use
PPI	Producer Price Index
PT&T	The Pacific Telephone and Telegraph Company
PU	Public Utilities
QAU	Quantifying Added Uncertainties
QF	Qualifying Facility
RCS	Residential Conservation Service
R&D	Research and Development
R&E	Research Experimentation
RT	Reporter's Transcript
SAM	Supply Adjustment Mechanism
San Diego	City of San Diego

APPENDIX E
Page 3

GLOSSARY

SCRUB	Schools Committee for Reducing Utility Bills
SDG&E	San Diego Gas & Electric Company
Shareholders	California Association of Utility Shareholders
Sher Bill	Miller-Warren Energy Lifeline Act of 1975
SoCal	Southern California Gas Company
SONGS	San Onofre Nuclear Generating Station
SRAM	Steam Revenue Adjustment Mechanism
Staff	Commission staff
SWAT	Southwest Area Transportation Planning Coordination Committee
TEFRA	Tax Equity and Fiscal Responsibility Act of 1982
Test Year	SDG&E's 1984 Rate Case Year
TOU	Time of Use
TURN	Toward Utility Rate Normalization
WMA	Western Mobilehome Association
WRO	Welfare Rights Organization

(END OF APPENDIX E)

APPENDIX F
Page 1

TABLE 1

	1984 Expense	1985 Expense	1984-85 Incremental Change
	($000)		
Electric 1/			
Heber	$10,537	$ 2,286	$(8,251)
Fixed Wheeling	13,248	15,838	2,590
SONGS I Sleeving	3,747	3,747	
Encina Lease	9,240	9,240	-
Amortizations			
Low Pressure Turbine	291	291	
Mexican Project	248	248	
Water Environmental Study	377	377	-
Postage	1,215	1,215	-
Total Electric	38,903	33,242	(5,661)
Gas			
Postage	701	701	-
Total Gas	701	701	-

(Red Figure)

1/ CPUC jurisdictional.

APPENDIX F
Page 2

TABLE 2

San Diego Gas & Electric Company
Electric Department
CPUC JURISDICTIONAL
1985 Expense Attrition

Line No.	Item	Labor	Non-Labor
		($000)	
	1984 Expenses in 1981 Dollars		
1	Production	22,044	44,238
2	Transmission	3,730	14,928
3	Distribution	19,303	10,839
4	Customer Accounts	8,000	4,927
5	Customer Service & Information	4,622	5,801
6	Administrative & General	22,155	33,346
7	Total 1984 Expenses (1981 $)	79,854	114,079
8	Escalation to 1984 Dollars	15,100	5,324
9	Total 1984 Expenses (1984 $)	94,954	119,403
10	Items Not Indexed 1/		38,903
11	Total To Be Indexed (Line 9 - Line 10)	94,954	80,500
12	Adopted 1984 Escalation Rates	3.30%	5.2631%
13	1984 Expenses in 1983 Dollars Line 11 ÷ (Line 12 + 100%)	91,921	76,475
14	Escalation Rates 2/3/		
15	Escalated Amounts (Line 13 x Line 14) 3/		
16	Incremental Change For Fixed Items 1/		(5,661)
17	Total Change Labor, Non-Labor (Line 15 + Line 16) 3/		
18	Total 1985 Labor, Non-Labor Expenses (Line 17 + Line 10 + Line 13) 3/		
19	Labor, Non-Labor Attrition (Line 19 - Line 9) 3/		
20	Total Labor + Non-Labor Attrition 3/		

1/ See Table 1.
2/ Compound rate for 1984 & 1985
3/ To be determined at time of attrition filing.

A.82-12-57 /ALJ/ra

APPENDIX F
Page 3

TABLE 3

San Diego Gas & Electric Company
Gas Department
CPUC JURISDICTIONAL
1985 Expense Attrition

Line No.	Item	Labor	Non-Labor
		($000)	
	1984 Expenses in 1981 Dollars		
1	Supply	69.9	(798.0)
2	Storage	798	1,015.7
3	Transmission	1,031.2	967.2
4	Distribution	9,376.6	2,443.0
5	Customer Accounts	4,615.0	2,330.5
6	Cust. Service and Information	2,358.2	6,839.5
7	Administrative & General	7,133	8,676.7
8	Total 1984 Expenses (1981 $)	25,382	21,474.6
9	Escalation to 1984 Dollars	4,790.4	1,359.9
10	Total 1984 Expenses (1984 $)	30,172.5	22,834.5
11	Items Not Indexed 1/		701.0
12	Total To Be Indexed (Line 9 - Line 10)	30,172.5	22,133.5
13	Adopted 1984 Escalation Rates	3.30%	5.2631%
14	1984 Expenses in 1983 Dollars Line 12 ÷ (Line 13 + 100%)	29,208.6	21,026.8
15	Escalation Rates 2/3/		
16	Escalated Amounts (Line 14 x Line 15) 3/		
17	Incremental Change For Fixed Items 1/		
18	Total Labor, Non-Labor (Line 16 + Line 17) 3/		
19	Total 1983 Labor, Non-Labor Expenses (Line 18 + Line 11 + Line 14) 3/		
20	Labor, Non-Labor Attrition (Line 19-Line 10) 3/		
21	Total Labor + Non-Labor Attrition 3/		

1/ See Table 1.

2/ Compound rate for 1984 & 1985

3/ To be determined at time of attrition filing.

APPENDIX F
Page 4

TABLE 4

San Diego Gas & Electric Company
Steam Department

1985 EXPENSE ATTRITION

Item	Labor	Non-Labor
1. Total O&M, A&G	176.0	88.0
2. Adopted 1984 Escalation Rates	3.30%	5.2631%
3. 1984 Expenses in 1983 Dollars Line 1 + (Line 2 + 100%)	170.4	83.6
4. Escalation Rates 1/		
5. Escalation Amount 2/		
6. Total 1985 Labor, Non-Labor Expenses (Line 5 + Line 3) 2/		
7. Labor, Non-Labor Attrition (Line 6 - Line 1) 2/		
8. Total Labor + Non-Labor Attrition 2/		

1/ Compound rate for 1984 and 1985.

2/ To be determined at time of attrition filing.

APPENDIX F
Page 5

TABLE 5

San Diego Gas & Electric Company

1985 ATTRITION RATE BASE, DEPRECIATION AND TAX ITEMS
NOT SUBJECT TO INDEXING 1/

Item	Electric	Gas	Steam
Additions to Rate Base 2/	$135,548	$23,243	$64
Depreciation Reserve 2/	60,336	12,455	42
Ad Valorem Taxes 2/	[illegible]	82	1
Depreciation Expense 2/	[illegible]	[illegible]	2
Income Tax Deductions 3/			
Tax Depreciation			
Federal	64,553	11,591	21
State	60,375	9,698	33
ITC Normalized	[illegible],884	219	1
ITC Deferred 4/	55,786	6,821	27
Deferred Taxes 5/	25,665	4,047	18
Interest 6/	53,211	8,975	23

1/ Total system.

2/ Additions to test year 1984 amounts.

3/ Replace 1984 test year amounts.

4/ Deduction from rate base for calculating interest only.

5/ Deducted from rate base.

6/ 1985 weighted cost of debt 4.89%.

APPENDIX F
Page 6

TABLE 6

San Diego Gas & Electric Company
Electric Department

1985 SUMMARY OF EARNINGS

	Total System	CPUC Jurisdictional
	(Thousands of Dollars)	
Operating Revenues		
1984 Adopted Revenues	$539,235.0	$537,483.0
Rate Base & Financial Attrition	22,349.0	21,400.0
Expense Attrition 1/	-	
Total Operating Revenues	561,584.0	558,883.0
Operating Expenses		
Production	66,678.8	66,282.0
Transmission	18,909.5	18,658.0
Distribution	30,142.0	30,142.0
Customer Accounts 2/	12,980.0	12,980.0
Customer Service & Information	10,422.7	10,423.0
Administrative & General 2/	56,082.0	55,939.0
Blythe Amortization ($84)	8,021.0	7,978.0
Subtotal	203,236.0	202,402.0
Labor Adjustment	15,146.1	15,100.0
Non-labor Adjustment	5,341.7	5,324.0
Expense Attrition 1/		
Subtotal after Adjustments	223,723.8	222,826.0
Depreciation & Amortization	70,896.6	70,697.0
Taxes Other Than Income	20,023.9	19,961.0
California Franchise Tax	18,437.4	18,304.0
Federal Corp. Income Tax	80,719.8	80,137.0
Total Operating Expenses	413,801.5	411,925.0
Net Operating Revenues	147,782.5	146,958.0
Rate Base	1,142,947.0	1,136,569.0
Rate of Return	12.93	12.93

1/ To be determined from Table 2 at time of attrition filing. Includes franchise fees and uncollectibles.

2/ Includes franchise fees and uncollectibles for rate base & financial attrition.

APPENDIX F
Page 7

TABLE 7

San Diego Gas & Electric Company
Gas Department

1985 SUMMARY OF EARNINGS

	(Thousands of Dollars)
Operating Revenues	
1984 Adopted Revenues	$107,643.0
Rate Base & Financial Attrition	4,833.0
Expense Attrition 1/	
Total Operating Revenues	112,475.0
Operating Expenses	
Gas Supply	-728.1
Gas Storage	1,813.8
Transmission	1,998.4
Distribution	11,819.6
Customer Accounts 2/	6,957.0
Customer Service & Information	9,197.7
Administrative & General 2/	15,924.8
Subtotal	46,983.2
Labor Adjustment	4,790.4
Non-Labor Adjustment	1,359.9
Expense Attrition 1/	
Subtotal after Adjustments	53,133.5
Depreciation & Amortization	13,852.4
Taxes Other Than Income	3,491.3
California Franchise Tax	3,393.5
Federal Corp. Income Tax	13,986.8
Total Operating Expenses	87,857.5
Net Operating Revenues	24,617.5
Rate Base	190,391.0
Rate of Return	12.93

1/ To be determined from Table 3 at time of attrition filing. Includes franchise fees and uncollectibles.

2/ Includes franchise fees and uncollectibles for rate base and financial attrition.

APPENDIX F
Page 8

TABLE 8

San Diego Gas & Electric Company
Steam Department

1985 SUMMARY OF EARNINGS

	(Thousands of Dollars)
Operating Revenues	
1984 Adopted Revenues	$417
Rate Base & Financial Attrition	8
Expense Attrition 1/	-
Total Operating Revenues	425
Operating Expenses	
Production	69
Distribution	82
Customer Accounts 2/	2
Administrative and General 2/	65
Subtotal	218
Labor Adjustment	32
Non-Labor Adjustment	14
Expense Attrition 1/	-
Subtotal After Adjustments	264
Depreciation & Amortization	42
Taxes Other Than Income	17
California Franchise Tax	7
Federal Corp. Income Tax	36
Total Operating Expenses	366
Net Operating Revenues	59
Rate Base	454
Rate of Return	12.93

1/ To be-determined from Table 4 at time of attrition filing. Includes franchise fees and uncollectibles.

2/ Includes franchise fees and uncollectibles for rate base and financial attrition.

(END OF APPENDIX F)

md

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY for authority to increase its rates and charges for electric, gas and steam service.	Application 82-12-57 (Filed December 24, 1982)

TO: PERSONS RECEIVING DECISION 83-12-065

Attached is a revised Appendix C which replaces Appendix C distributed with D.83-12-065 in this proceeding. The revised appendix contains adopted rates for electric, steam, and gas services.

Dated December 29, 1983, at San Francisco, California.

JOSEPH E. BODOVITZ
Executive Director

APPENDIX C
AUTHORIZED RATES
Page 1

San Diego Gas & Electric Company
SUMMARY OF ADOPTED ELECTRIC RATES */

Applicant's electric rates, charges, and conditions are changed to the extent set forth in this appendix. Base charge for SDG&E includes revenue for Electrical Revenue Adjustment Mechanism (ERAM), Conservation and Load Management Programs Adjustment Clause (CALPAC), Load Management Adjustment (LMA), and Major Additions Adjustment Clause (MAAC).

Schedules DR, DM, DS[a/], DT[b/]

	Per Meter Per Month	
Customer Charge	Eliminated	
Energy Charge (per kWh)	Lifeline	Non-Lifeline
Base	.06682	.06682
ECAC and AER	.02806	.07452
MINIMUM BILL	$5.00	

a/ Schedule DS

The effective rate of the single family domestic service schedule, applicable in the territory in which the multi-family accommodation is located, less $0.65 per unit discount.

b/ Schedule DT

The effective rate of the single family domestic service schedule, applicable in the territory in which the multi-family accommodation is located, less $6.51 per unit discount.

Schedule A

	Per Meter Per Month	
Customer Charge	$2.20	No Change
Energy Charge (per kWh)		
Base	.0634	
ECAC and AER	.05483	
MINIMUM CHARGE	Customer Charge	No Change

*/ Includes increase of .396¢ per kWh to MAAC and a reduction of .396¢ per kWh to ECAC (D.83-09-007 and 83-11-091).

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San Diego Gas & Electric Company

SUMMARY OF ADOPTED ELECTRIC RATES

Schedule AD

APPLICABILITY

Applicable to general service including lighting, appliances, heating and power or any combination thereof where the customer's monthly maximum demand exceeds 20 KW.

	Per Meter Per Month
Customer Charge	$10.00
Demand Charge	
Per KW	4.00
Energy Charge (per KWh)	
Base	.05149
ECAC and AER	.05483
MINIMUM CHARGE	Eliminated

SPECIAL CONDITION

2. Primary Voltage Discount

Same as for Schedule AL-TOU.

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San Diego Gas & Electric Company

SUMMARY OF ADOPTED ELECTRIC RATES

Schedule AL-TOU

APPLICABILITY

Applicable to all customers whose maximum monthly demand is expected to be between 500 kW and 4,500 kW, and to customers whose maximum monthly demand exceeds 500 kW for three consecutive months. Any customer whose maximum monthly demand has fallen below 450 kW for 12 consecutive months and who does not meet the demand requirements for any other mandatory schedule may, at his option, elect to continue service under this schedule or be served under any other applicable schedule. This schedule is available on an optional basis to customers whose maximum monthly demand exceeds 4,000 kW and to the first 500 customers per year whose maximum monthly demand is less than 500 kW who satisfy Special Condition 8.

	Per Meter Per Month	
Customer Charge	$20.00	No Change
Demand Charge		
Maximum Demand during the On-Peak Period, per kW	7.31	No Charge

Energy Charge (per kWh)	On-Peak	Semi-Peak	Off-Peak
Base	.06476	.05876	.03476
ECAC and AER	.05483	.05483	.05483

MINIMUM CHARGE	Eliminated

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San Diego Gas & Electric Company

SUMMARY OF ADOPTED ELECTRIC RATES

Schedule AL-TOU (continued)

TIME PERIODS

All time periods listed are applicable to local time.

Peak Weekdays	S:	11 am - 6 pm
	W:	5 pm - 8 pm
Semi-Peak Weekdays	S:	6 am - 11 am
		6 pm - 10 pm
	W:	6 am - 5 pm
		8 pm - 10 pm
Off-Peak Weekdays Weekends Holidays	Annual:	10 pm - 6 am

Summer(S): May 1 - September 30 based on service rendered

SPECIAL CONDITIONS

1. Primary Voltage and Energy Discount. A primary voltage and energy discount will only be allowed where delivery is made and energy is received at an available standard voltage. Under these circumstances, the charges before power factor adjustment and energy cost adjustment will be reduced by 3% in the range of 2 kV to 10 kV, 4% in the range of 10.1 kW to 25 kV, and 7% above 25 kV.

5. Time-of-Use Meter Malfunction

(b) Failure of Meter Timing. In the event that the timing device on the time-of-use meter fails, causing the on-peak, semi-peak and off-peak energy consumptions and billing demand to be incorrectly registered, the energy sales and billing demand will be prorated to time periods based on the energy division and billing demand during the three previous billing periods.

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San Diego Gas & Electric Company

SUMMARY OF ADOPTED ELECTRIC RATES

Schedule AL-TOU (Continued)

8. Optional Time-of-Use Service

(a) Applicability. This schedule is optional to any customer whose maximum monthly demand is less than 500 kW, provided they have permanently installed equipment or adopted operating procedures designed to reduce at least 1,680 on-peak period kWhrs per year.

(b) Load Checks. The utility has the right to monitor time-of-use load and make facility inspections to verify that permanently installed on-peak conservation equipment, as stated in 8(a), is properly installed and in operation. In the event that a customer is found, by inspection or other means, not to have, or be operating, the necessary equipment, the utility shall have the right to rebill the customer's previous 11 months based on his otherwise appropriate schedule.

(c) Metering. The utility will supply, own, and maintain all necessary meters and associated equipment utilized for billings. In addition, and for purposes of monitoring customer load, the utility may install at its expense, load research metering. The customer shall supply, at no expense to the utility, a suitable location for meters and associated equipment used for billing and for load research.

Schedule AL-CG

Customer charge, demand charges, energy charges, and Time-of-Use periods are the same as for AL-TOU.

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San Diego Gas & Electric Company

SUMMARY OF ADOPTED ELECTRIC RATES

Schedule A6-TOU

APPLICABILITY

Applicable to all customers receiving service on Schedule A-6 as of December 31, 1983 and thereafter to new customers whose maximum demand in any time period is 4,500 kW or greater and to existing customers on other schedules whose monthly maximum demand is 4,500 kW or greater for three consecutive months. Any customer, at his option, may elect to continue service under this schedule or be served under any other applicable schedule.

		Per Meter Per Month	
Customer Charge		$600.00	No Change
Demand Charge			
Customer's Contribution to Monthly System Peak, per kW		$ 8.71	No Change

Energy Charge (per kWh)	On Peak	Semi Peak	Off Peak
Base	.06476	.05876	.03476
ECAC and AER	.05483	.05483	.05483

MINIMUM CHARGE Eliminated

TIME PERIODS

Same as for AL-TOU

SPECIAL CONDITIONS

2. Primary Voltage and Energy Discount. A primary voltage and energy discount will only be allowed where delivery is made and energy is received at an available standard voltage. Under these circumstances, the charges before power factor adjustment and energy cost adjustment will be reduced by 3% in the range of 2kV to 10 kV, 4% in the range of 10.1 kV to 25 kV, and 7% above 25 kV.

Schedule A6-CG

Customer charge, energy charges, and time-of-use periods are the same as for A6-TOU. Demand charge is $7.27/kW.

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San Diego Gas & Electric Company

SUMMARY OF ADOPTED ELECTRIC BASE RATES

Schedule PA	Per Meter Per Mwh
Customer Charges	
0-500 kWh	$ 4.
501-2500 kWh	$ 7.
2501-10000 kWh	$ 11.
Over 10000 kWh	$ 20.
Energy Charge (per kWh)	
Base	.05799
ECAC and AER	.05483

Lighting Schedules

No Changes in Schedules LS-1, LS-2, LS-3, OL-1, and DWL

EXPERIMENTAL SCHEDULES

Schedule Pa-TOU

TOU Metering Charge	$ 7.00
Energy Charge (per kWh)	
Base	
On Peak	.14010
Off Peak	.025
ECAC and AER	.05483

APPENDIX
Page 8

San Diego Gas & Electric Company

SUMMARY OF ADOPTED ELECTRIC RATES

D-ATOU

	Lifeline	Non-Lifeline	Per Meter Per Month
Customer Charge			Eliminated
Energy Charge (per kWh)			
Base			
On Peak			.16832
Off Peak			.01618
ECAC and AER	.02806	.07452	
MINIMUM BILL			$5.00

D-UTOU

	Lifeline	Non-Lifeline	
Energy Charge (per kWh)			
Base			
On Peak			.07535
Off Peak			.00639
ECAC and AER	.02806	.07452	

APPENDIX C

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San Diego Gas & Electric Company

GAS DEPARTMENT

Gas rates are shown in the companion decision issued today in A.83-09-58.

STEAM DEPARTMENT

The adopted base rates for the Steam Revenue Adjustment Mechanism (SRAM) are as follows:

Schedule 1: $3.194 per mlbs.

Schedule 2: $3.228 per mlbs.

(END OF APPENDIX C)

California Association of Utility Shareholders	(CAUS, shareholders)
California Energy Commission	(CEC)
California-Nevada Community Action Association	(CAL-NEVA)
Federal Executive Agencies	(FEA)
Independent Energy Producers	(IEP)
Insulation Contractors Association	(ICA)
Edward J. Neuner, for himself	(Neuner)
City of San Diego	(San Diego)
San Diego Rock Producer's Association	(Rock Producers)
Schools Committee for Reducing Utility Bills	(SCRUB)
The Sierra Club	(Sierra Club)
Welfare Rights Organization	(WRO)
Western Mobilehome Association	(WMA)

2. Decision Summary

By this decision the Commission grants SDG&E permission to raise its rates by $21 million per year effective January 1. SDG&E had requested a $127 million increase when it filed its application on Christmas Eve in 1982. After the Commission held 65 days of hearings, all in San Diego, the company had pared its request to $65 million whereas the Commission's staff had recommended no increase at all.

The Commission held four sessions over two days last May to hear comments from the customers of SDG&E. These were far ranging. Persons on fixed incomes deplored the possibility of increased power bills; some customers thought SDG&E was mismanaged by overpaid managers; some people wanted more spent on conservation and some less; and almost everyone thought it was time for SDG&E to tighten its belt as everyone else has had to do.

In designing the new electric rates that will go into effect on January 1, the Commission orders SDG&E to move to a full marginal cost allocation of revenues to its various customers. The method attempts to put the incremental cost of providing energy on those customers most responsible for that cost. The method causes some interesting effects on the increases for the various classes of service. On the average, residential rates will go down 2.9%, commercial and industrial customers will pay an average of 3.7% more, and agricultural users will pay 2.5% less. Streetlighting rates will not be changed until SDG&E comes up with a satisfactory marginal cost study for that service, which the Commission orders the utility to complete and present in 1985.

One of the stickiest issues in the case was what to do with SDG&E's Blythe Site, a piece of property left over from the company's abandoned attempt to develop a nuclear generating facility near Blythe, California, which was known as the Sundesert project. Most participants in the proceedings urged the Commission to keep the site available for a future power plant, but, at the same time, urged that it be taken out of the company's rate base so customers would not have to support it. That support has been costing ratepayers as much as $8.5 million per year. The Commission breaks the cost of the site into two pieces, development costs, which no longer have any value, and land and water rights. The development costs are to be written off over ten years, and the land and water rights will be held in rate base until there is a final decision on what to do with the property. The land and water rights have a current value of about $30 million on the open market and are on the books for $19.5 million. The cost to ratepayers of preserving the site, which may be worth as much as $400 million as a power plant site by 1992, will be $6.8 million for at least 1984 and 1985.

The Commission's decision cuts the return on equity capital of SDG&E stockholders to 16% compared to the current 16½% authorized for 1982 and 1983. The overall rate of return granted the company is 12.82%.

The Commission orders SDG&E to cut back its conservation activities in 1984 to about the 1982 level. In particular, heavy cuts are made in requested 1984 funds for support programs for the commercial/industrial sector and residential audits; modest cuts are made to weatherization programs. It should be noted that SDG&E was in favor of even heavier cuts; its requested funds reflected what it believes would be necessary to continue its programs at a level equivalent to past years' levels and growth. The Commission adopts a conservation policy for SDG&E for the first time. The policy stresses supporting mandated programs, requiring new programs to be cost-effective, phasing out incentive-payment programs not shared by all ratepayers or which would be undertaken by customers without incentives, and continuing programs that are worthwhile from the standpoint of equity.

The Welfare Rights Organization convinced the Commission to adopt several new tariff provisions which enlarge the rights of SDG&E's customers concerning payment of bills and termination of service. SDG&E will now have to notify customers of the reason their service is being terminated, payment plans for overdue bills will be more flexible, informal litigation of bills by the Commission's staff will be easier to initiate, and customers will be better informed of options they have under SDG&E's tariffs.

The decision sets up a mechanism which will allow SDG&E to adjust its rates on January 1, 1985 for valid and specific increases in the cost of doing business. No further general rate increase will be considered by the Commission before January 1, 1986.

3. Statements of SDG&E Customers

During the hearings on this application, four sessions were held to receive comments and questions from SDG&E's customers. The sessions were held morning and evening on May 23, and afternoon and

TABLE 12
Page 1 of 6

SDG&E
Electric Department
Adopted Results of Operations
At Present Rates
($1000)

TOTAL OPERATING REVENUES	$ 528417.0
OPERATING EXPENSES	
PRODUCTION	$ 66678.8
TRANSMISSION	18909.5
DISTRIBUTION	30142.0
CUSTOMER ACCOUNTS	12903.4
CUST. SERVICE & INFORMATION	9883.5
ADMINISTRATIVE & GENERAL	55655.6
BLYTHE AMORTIZATION (S8A)	6766.6
SUBTOTAL	$200939.4
LABOR ADJ.	$ 15137.7
NON-LABOR ADJ.	5362.0
UNSPENT FUNDS	-924.0
SUBTOTAL AFTER WAGE ADJ.	$220515.1
DEPRECIATION & AMORTIZATION	$ 66712.7
TAXES OTHER THAN INCOME	18755.9
CALIF CORP FRANCHISE TAX	16491.7
FED CORP INCOME TAX	72953.6
TOTAL OPERATING EXPENSES	$395429.0
NET OPERATING REVENUES ADJUSTD	$132988.0
RATE BASE	$1095074.0
RATE OF RETURN	12.14%

TABLE 12
Page 2 of 6

SDG&E
Electric Department
Adopted Results of Operations
At Authorized Rates
($1000)

TOTAL OPERATING REVENUES	$543919.0
OPERATING EXPENSES	
PRODUCTION	$66678.8
TRANSMISSION	18909.5
DISTRIBUTION	30142.0
CUSTOMER ACCOUNTS	12940.3
CUST. SERVICE & INFORMATION	9883.5
ADMINISTRATIVE & GENERAL	55961.0
BLYTHE AMORTIZATION ($84)	6766.6
SUBTOTAL	$ 201281.7
LABOR ADJ.	$ 15137.7
NON-LABOR ADJ.	5362.0
UNSPENT FUNDS	-924.0
SUBTOTAL AFTER WAGE ADJ.	$ 220857.4
DEPRECIATION & AMORTIZATION	$ 66712.7
TAXES OTHER THAN INCOME	18755.9
CALIF CORP FRANCHISE TAX	17947.1
FED CORP INCOME TAX	79257.6
TOTAL OPERATING EXPENSES	$ 403530.7
NET OPERATING REVENUES ADJUSTD	$ 140388.3
RATE BASE	$1095074.0
RATE OF RETURN	12.82%

TABLE 12
Page 3 of 6

SDG&E
Gas Department
Adopted Results of Operations
At Present Rates
($1000)

TOTAL OPERATING REVENUES	$103428.0
OPERATING EXPENSES	
GAS SUPPLY	$ -728.1
GAS STORAGE	1813.8
TRANSMISSION	1998.4
DISTRIBUTION	11819.6
CUSTOMER ACCOUNTS	6935.5
CUST. SERVICE & INFORMATION	8722.2
ADMINISTRATIVE & GENERAL	15662.6
TELEPHONE DIVESTITURE (584)	.0
SUBTOTAL	$ 46224.0
LABOR ADJ.	$ 4777.6
NON-LABOR ADJ.	1343.9
UNSPENT FUNDS	-803.6
SUBTOTAL AFTER WAGE ADJ.	$ 51541.9
DEPRECIATION & AMORTIZATION	$ 13354.4
TAXES OTHER THAN INCOME	3409.3
CALIF FRANCHISE TAX	2816.0
FED CORP INCOME TAX	11563.3
TOTAL OPERATING EXPENSES	$ 82664.9
NET OPERATING REVENUES ADJUSTD	$ 20743.1
RATE BASE	$181674.0
RATE OF RETURN	11.42%

TABLE 12
Page 4 of 6

SDG&E
Gas Department
Adopted Results of Operations
At Authorized Rates
($1000)

TOTAL OPERATING REVENUES	$108787.0
OPERATING EXPENSES	
GAS SUPPLY	$ -728.1
GAS STORAGE	1813.8
TRANSMISSION	1998.4
DISTRIBUTION	11819.6
CUSTOMER ACCOUNTS	6948.2
CUST. SERVICE & INFORMATION	8722.2
ADMINISTRATIVE & GENERAL	15790.1
TELEPHONE DIVESTITURE(584)	.0
SUBTOTAL	$ 46364.2
LABOR ADJ.	$ 4777.6
NON-LABOR ADJ.	1343.9
UNSPENT FUNDS	-803.6
SUBTOTAL AFTER WAGE ADJ.	$ 51682.1
DEPRECIATION & AMORTIZATION	$ 13354.4
TAXES OTHER THAN INCOME	3409.3
CALIF FRANCHISE TAX	3317.0
FED CORP INCOME TAX	13733.5
TOTAL OPERATING EXPENSES	$ 85496.3
NET OPERATING REVENUES ADJUSTD	$ 23290.7
RATE BASE	$181674.0
RATE OF RETURN	12.82%

TABLE 17

San Diego Gas & Electric Company

Adopted Revenue Allocation

(Test Year 1984)

Class of Service	Adopted Sales (Gwh)	Present Rates - Revenue (as Nov. 22, 1983) Base (000's)	Offset (000's)	Effective (000's)	Av.Rate (c/kwh)	Marginal Cost Data: Short-Run Marginal Cost Rates	Revenue (000's)	Proposed Rates - Revenue Base (000's)	Change (%)	Effective (000's)	Change (%)	Av.Rate (c/kwh)
	(1)	(2)	(3) <a>	(4)	(5)	(6)	(7)	(8) <b>	(9)	(10) <c>	(11)	(12)
Residential......:	3466.10	199897	211626	411523	11.87	9.23	319921	187826	-6.04	399452	-2.93	11.52
Comm. & Ind......:	6572.49	308199	458886	767085	11.67	9.69	636874	336312	9.12	795198	3.66	12.10
Agriculture......:	178.95	8882	12392	21274	11.89	9.29	16607	8343	-6.07	20735	-2.53	11.59
Sub-Total Marginal Cost Classes....:	10217.54	516978	682904	1199882	11.74	----	973402	532480	3.00	1215384	1.29	11.90
St. Lighting.<d>.:	87.37	8762	6136	14898	17.05	----	----	8762	.00	14898	.00	17.05
Sub-Total ....:	10304.91	525740	689040	1214780	11.79	----	----	541242	2.95	1230282	1.28	11.94
Resale...........:	.12	1567	6194	7761	----	----	----	1567	----	7761	----	----
Sub-Total........:	10305.03	527307	695234	1222541	11.86	----	----	542809	2.94	1238043	1.27	12.01
Miscellaneous....:	----	6929	----	6929	----	----	----	6929	----	6929	----	----
Total ....:	10305.03	534236	695234	1229470	11.93	----	----	549738	2.90	1244972	1.26	12.08

Notes :

<a> Total Offset Revenue for Column (3) contains .... :ECAC = 562506
:AER = 26517
:CALPAC = 2268
:ANRER = 11239
:AOR = 53416
:ERAM = 39288
:Total = 695234

<b> Column (8) = Column (10) - Column (3).

<c> Effective Revenues for MC Classes (Column 10) are allocated by the Equal Percentage of Marginal Cost (EPMC). Column (10) = (1215384)/973402) x Col. (7).

<d> St. Lighting includes : LS-1, LS-2, OL-1C, OL-1R, and DWL.

sophisticated and an attempt to keep up with new and innovative methods would be an unjust penalty for progressive management. We urge the staff to use the new tools available by developing its own expertise and using the new capabilities of the utilities by cooperative use of utility facilities through data requests.

5.1.2 Labor Escalation Factors

SDG&E uses DRI forecasts and its contracted wage agreements to estimate its labor escalation factors. SDG&E's original factors exceed the staff's estimates; however, SDG&E amended its factors to reflect more recent DRI forecasts and, as Table 2 shows, SDG&E estimates for '84 and '85 are now below staff's. However, there is the issue of the staff policy recommendation that, for ratemaking purposes, wage increases should not exceed the increase in the cost of living as measured by the CPI-All Urban Index (CPI-U) under a baseline or neutral situation. To convince us of this, staff goes into a lengthy argument in its brief liberally sprinkled with citations to Commission and court decisions. Nowhere, however, in testimony or argument, does it present any evidence that SDG&E does not bargain effectively with its employees. In fact, as shown on Table 3 which is taken from Page 2-2 of staff's Exhibit 24, for the latest five years of actual data, SDG&E has done quite well against the U.S. and San Diego CPI-Us.

TABLE 3

HISTORICAL PERCENTAGE CHANGES

	1978	1979	1980	1981	1982
United States CPI-U	7.7	11.3	13.5	19.3	6.0
San Diego CPI-U	9.9	16.5	15.1	13.4	7.0
SDG&E Wages	7.0	7.0	9.5	12.4	8.5

base under that approach between 1966 and 1972; we will assume it would have been 6 years or 72 months. Adding the 72 to 58 used by SDG&E gives us 130; dividing 130 by 196, the total time the property was held by SDG&E, gives a percentage of 66.3%. When this is multiplied times the $2,375,116, we obtain a total applicable to ratepayers of $1,574,702; subtracting from that the $702,842 which has already been booked in 1982, gives $871,860 which we will book in 1984 and 1985. This treatment is similar to our treatment of the SONGS sleeving writeoff. Therefore, we will book $436,000 to electric revenue in 1984 and in the attrition year 1985.

14. Rate of Return

For 1982 and 1983 test years the Commission granted SDG&E 12.92% and 13.25% rates of return. These included a return on equity of 16.25%. In the company's NOI and application which were filed in the fall of 1982 and late December 1982, respectively, SDG&E asked for a rate of return of 14.93% with a return on equity of 19%. At the prehearing conference on February 3, 1983 it reduced its request to 14.05% overall and a 17.5% return on equity. In June and again in September 1983 the company issued $150,000,000 in industrial development bonds (IDB)[3] at favorable interest rates of 10.56% and 10.50%. This caused it to reduce its request further to 13.44% overall with 17.5% on equity. This was one of the major reasons SDG&E reduced its revenue increase request from the original amount of $126.8 to $65.3 million.

A significant development during the hearing phase of these proceedings was the upgrading of SDG&E's bonds. The company had as its long-term goal an upgrading sometime in 1984.

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[3] These bonds are tax exempt and are issued at interest rates generally 300 basis points below market.

There have been several changes in the recommendations on rate of return during the course of these hearings including updates made at the hearing in September. Table 7 shows the latest company request and the recommendation by the staff. The only other recommendations concerning rate of return were made by FEA and the California Association of Utility Shareholders. FEA recommended the return on equity be 14% to 15% and CAUS 18%.

Table 7

Recommended Rate of Return - 1984

Component		Capitalization Ratio	Cost	Cost
		SDG&E		
Long Term Debt		45.84%	10.51%	4.82%
Preferred Stock		11.55	10.08	1.16
Common Equity		42.62	17.50	7.46
	Total	100.00%		13.44%
		Staff		
Long Term Debt		45.50%	10.50%	4.78%
Preferred Stock		11.50	10.08	1.16
Common Equity		43.00	16.00	6.88
	Total	100.00%		12.82%

14.1 Capitalization Ratios

There is very little difference between the company and the staff capitalization ratios. The primary difference is in common equity where the staff has included 43%, which is the goal of SDG&E in the short term. The preferred stock figure is almost the same for both the staff and the company, which leaves the long-term debt ratio as a residual, it being a function of 100% minus the common equity and preferred stock percentages. There was some comment during the hearing concerning the inclusion of bankers' acceptances in SDG&E's capital structure. The staff proposed that they be removed because the ECAC mechanism currently compensates SDG&E for the carrying cost of fuel oil inventory, that being the short-term financing purpose of the bankers' acceptances. By stipulation bankers' acceptances have been excluded by SDG&E and the staff in favor of consideration of their ratemaking treatment of fuel oil inventory carrying costs in OII 82-04-02, the ECAC incentives case.

We will adopt the staff's capitalization ratios because it should give the company more of an incentive to achieve its announced goal of a 43% ratio for common equity.

14.2 Long-Term Debt and Preferred Stock Costs

There is practically no difference between SDG&E and Staff for these costs. We will adopt staff figures to be consistent with the adoption of its capitalization ratios.

14.3 Return on Equity

One of the most significant, and perhaps the most difficult, factors to determine in a rate case is return on common equity. We have four recommendations to consider in this case: SDG&E at 17½%, the staff's range of 15.75 to 16.25%, FEA at 14 to 15%, and CAUS at 18%. As we have said in so many decisions before, all of the recommendations will sift down, be considered by the Commission, and, in the end, we will make a subjective judgment. Most of the witnesses start with the Hope and Bluefield cases.[4] Although in the case of FEA, their brief had some interesting comments on these two cases and how they should be considered which we will discuss later in this decision.

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[4] Federal Power Commission v Hope Natural Gas Co., (1944) 320 US 591. Bluefield Waterworks and Improvement Co. v West Virginia Public Service Commission, (1923) 262 US 679.

14.3.1 Position of SDG&E

SDG&E presented two witnesses in support of its position, Robert Korpan, Vice-Pesident of Finance for SDG&E, and Eugene W. Meyer, Vice-President and Director of Kidder Peabody and Company, Inc.

Witness Korpan made the most comprehensive presentation for SDG&E in attempting to demonstrate the reasonableness of SDG&E's requested 17.5% return on equity. He concentrated on the cost of capital and fair rate of return from the prospective of what the financial markets require. Witness Meyer made a presentation on what he believes the current market conditions reflect in attempting to support witness Korpan's 17.5%. In particular, Meyer noted the need for the Commission to maintain its course of enabling SDG&E to continue what he considered to be SDG&E's prudent financial policies so that it could reduce the cost of capital and minimize rates in the future. Both witnesses emphasized what they believe to be the severe impact of higher costs on SDG&E's ratepayers due to past bond downgradings, common stock dilutions, and lack of financial community suport. They focused on the importance of SDG&E's market-to-book ratio as a benchmark for ascertaining the adequacy of past allowed returns.

Korpan based his equity return recommendation on three specific approaches: the risk premium method, a discounted cash flow analysis, and the comparable earnings approach.

SDG&E used two risk premium methods to make its determinations. Risk premium is a method that assumes the common equity investor demands a premium above returns received by the bondholder in order to compensate the investor for additional risk. Korpan used two different methods to identify his estimate of the amount of the premium. The first used the earnings/price ratio as a cost of equity proxy, and the second used the difference between A and B bond yields. By these methods Korpan arrived at a current cost of equity of 17.81% and a prospective cost of equity of 18.65%. He confirmed these results by the use of yields on 3- to 5-year government bonds as a conservative, risk-free proxy which produced a prospective cost of 18.44%.

Korpan's second method was a discounted cash flow method of equity analysis. This assumes that along with a certain return in the form of a dividend yield, an investor expects future growth of the investment. By this method Korpan developed a dividend yield of 12.15% and a growth component of 6.19%. By blending these two figures Korpan's discounted cash flow approach resulted in a current cost of equity of 16.70% and a prospective cost of 18.34%.

Korpan's comparable earnings analysis sought to compare the cost of capital for enterprises similar to SDG&E in risk. He selected a group of 10 utilities he thought were comparable in terms of their electric and gas percent of total revenue, their bond ratings, and their beta coefficient. Beta is a measure of how closely the return on a particular stock moves with the return on the market as a whole. Korpan's comparable earnings approach resulted in a cost of equity of 18.53%.

14.3.2 <u>Presentation of the Commission Staff</u>

The staff presented witness Edwin Quan, a financial analyst from the Commission's Revenue Requirements Division. Witness Quan also used the same three approaches used by SDG&E, that is, the risk premium, discounted cash flow, and comparable earnings tests.

Quan's risk premium approach involved the 10-year period made up of two consecutive 5-year periods 1973 through 1982. He compared SDG&E's earnings price ratio to A-rated bond yields between 1973 and 1974 and B-rated bond yields from 1975 to 1982. On this basis he determined that between 2.61 and 3.46 percentage points should be added to his 13% estimate of long-term debt cost for 1984 and 1985 to obtain the estimate of return on equity. The result was a range of 15.61% to 16.46%.

For his discounted cash flow analysis Quan derived figures by combining the investor's expected yield of 11.23% with the 4.5% to 5.5% expected growth rates and the 4.65%-4.80% sustainable growth rates. The result of his analysis indicates that SDG&E's cost to common equity ranges from 15.73% to 16.23% using historical growth rate assumptions and 15.88% to 16.03% using sustainable growth rates.

Quan's comparable earnings approach indicates that investors require a range of between 14.85% and 16.72% for comparable risk companies. His average required return is 15.88%. Using a sustainable growth rate and considering all growth assumptions, the required return would be 15.77%. Quan testified that the staff recommendation would fairly compensate investors for having foregone purchase of comparable risk utility stocks had they purchased SDG&E's stock.

14.3.3 Presentation of FEA

The FEA called Basil L. Copeland, Jr. as its witness on cost of capital. Copeland used a variation of the discounted cash flow method to determine his estimates. Copeland used the basic approach of determining the total required return as the combination of required dividend yield plus the expected growth rate. Copeland used several methods to determine his final estimate of between 14% and 15% as a fair return on common equity. His analyses included consideration of the returns on 97 of the 106 electric utilities on the New York stock exchange. He considered the utilities to be a homogenous group and conceded that if he were to make a recommendation for any of the 97, of which Edison, PG&E and SDG&E are included, he would recommend the same rate of return on common equity regardless of any differences in bond ratings.

FEA in its brief attacks the dependence of several of the witnesses on the Hope and Bluefield decisions, claiming that those decisions, in particular, Hope, had in mind investors and not consumers. FEA makes the point that apparently the witnesses who seem to depend on those two cases do so with the idea that the Commission is legally bound somehow to reflect in its decisions all of the tests which Hope and Bluefield set up. These tests are primarily whether the decision of the Commission results in the company maintaining its financial integrity and compensating its investors for risks they assume, risks which are comparable to the risks in other enterprises. Also, the utility should have an opportunity to earn a return on the value of the property which it employs for the public, a return which is equal to that generally being made at the time and in the same general part of the country on investments in other business undertakings having similar risks and uncertainties.

We point out for FEA that the Commission has always determined a fair and reasonable rate of return based on a judgment of all of the facts before it and not as a direct result of rigid, technical formulas. Our determination of what is a fair and reasonable rate of return depends on the facts of each individual case, together with the economic situation in effect at the time of the decision; and, although we are certainly cognizant of what the court has said in Hope and Bluefield, we do not believe those decisions compel us to make our determinations based only on the tests as outlined by those decisions. We agree with the Hope and Bluefield standards, such as capital attraction and commensurate returns, do not define the rate of return which a Commission must allow. They define, as pointed out by FEA, a dimension of the investors' interest and it is our duty to also consider the consumers' interest in making our final determination on an appropriate rate of return. That is what we will do.

14.3.4 <u>Presentation of CAUS</u>

The California Association of Utility Shareholders sponsored Philip C. Presber as its witness. Presber made a recommendation only on a fair return on common equity which he judged to be 18%. He based his determination primarily on projections of earnings, dividends, and book value for 1983 through 1985. Presber's recommendation is higher than that of any other party to the proceeding, including SDG&E. Presber believes that SDG&E has had a long history of lower than required returns on common equity. He sees from this a result which has not allowed SDG&E shareholders a fair return on their investments since 1972. He notes that the market value of SDG&E shares has been below book value for many years. He claims that since 1972, if calculated on the basis of the total shares offered each year, SDG&E has sold 37 million shares of common stock below book value. CAUS summarizes the consequences of this in its brief as follows: SDG&E had to sell 37 million shares of common stock below book value, or 220% of the total common stock outstanding at the end of 1972. These shares were sold for $486 million, an average of 25% below their book value, which resulted in dilution of $142 million, an amount equal to 72% of the common stockholders' equity at the beginning of the period. That $142 million was taken from existing shareholders and given to purchasers of new stock to entice them to buy stock so that the company could satisfy the demands of its customers for service. The result of this dilution was that the 10-year average, 1973 to 1982, calculated return on common investment of 11.5% was actually a mere 8.1%. Thus, the earnings per share by conventional calculation overstates the actual earnings by 42%. (See Exhibit 85, Table II, Column H.) CAUS believes all this has an adverse impact on consumers by raising the cost of capital through a lowering of SDG&E's bond rating. CAUS believes this approach supports the estimate by Korpan that approximately $21 million per year in additional revenues are required of consumers to support the higher cost of capital for SDG&E. CAUS believes the 18% it recommends on common equity will enable the company to continue to earn its authorized rate of return as it has for approximately the last 6 months, and enable it to sell common stock at or above book value.

CAUS recognizes the progress being made on many fronts financially for SDG&E and applauds the Commission, its staff, and the management of the company for this; but it maintains that if this momentum is to be maintained, a return of 18% on common equity is required.

14.3.5 Position of the City of San Diego

San Diego made no direct presentation on rate of return but through cross-examination and its brief brought out its position. San Diego maintains that the current return on equity of 16.25% was set by the Commission when the prime rate was about 20%, inflation was in double digits, and interest rates on corporate securities were around 16% or more. It argues the Commission did not believe SDG&E could achieve an A rating in 1982 or 1983 when it set the return on equity at 16.25%. However, San Diego points out the company did, in fact, achieve its A rating in the middle of 1983, at which time SDG&E was earning about a 15.8% return on equity.

San Diego believes there is no support for SDG&E's requested 17.5% rate of return in view of the fact that its stock is selling above book value and its ratings have been improved by both Standard and Poor's and Moody's. The Commission authorized a 16.25% rate of return in the last proceeding in spite of the fact that SDG&E was requesting 19%. The company is currently making 15.8% return from a ratemaking standpoint and 17% from what witness Korpan describes as a financial standpoint, and, finally, interest rates have softened somewhat since 1981.

San Diego submits that the Commission should take all of these factors into account and recommends that a rate of return on common equity be set in the vicinity of 15% for the test year 1984.

14.3.6 Position of Welfare Rights Organization

WRO's position is that the record indicates the Commission should not grant a rate of return on equity higher than the 16.25% granted in the 1982 general rate case. It contends that the record indicates a lower return could be authorized. WRO bases its recommendation on the improvement in all financial aspects of SDG&E's operation which have been shown in this proceeding.

WRO, in commenting on the specific recommendations of the parties, believes that SDG&E has totally failed to take into account current conditions in making its recommendation of a 17.5% return on equity. The staff's recommended return suffers from the use of outdated data and the recommendation of federal executive agencies of 14% to 15% is sufficient. WRO believes the interests of SDG&E's ratepayers have been sidelined by the Commission in its overzealous support of SDG&E's pursuit of an improved financial condition. It believes that now that the ratepayers have brought SDG&E its desired credit rating they are entitled to reap the promised benefits, a decreased cost of capital and the consequently lower rate of return.

14.4 Adopted Rate of Return

We have considered all of the evidence and the arguments in this proceeding and are of the opinion that a rate of return on equity of 16.00% for 1984 and 1985 is reasonable. We make this determination primarily on the basis that we want to see San Diego's momentum toward financial recovery continued, but we also recognize the economic and financial improvements noted in Section 14.3.5. We note the 16.00% is the midpoint of the staff recommendation and is only .25 points below the return we authorized in the 1982 rate case. The 17½% and 18% recommended by the company and CAUS, respectively are clearly too high for the conditions in effect today. The 14 to 15% recommended by FEA is based on what the record shows to be an average of a large cross-section of electric and gas utilities in the United States. The recommendation of FEA would be applied to those utilities regardless of their bond rating. We reject that approach as being too simplistic for the conditions at SDG&&E.

We want the 16.00% to be a continuing signal to the financial community and investors in SDG&E that the Commission is serious about the financial recovery of this company. We believe 16.00% on equity will ensure that SDG&E remains healthy and securely capable of serving its customers.

Table 8 summarizes the adopted capital structure, cost of capital, and consequent authorized overall rate of return of 12.82%.

Table 8

Adopted Rate On Return - 1984

Component	Capitalization Ratio	Cost	Weighted Cost
Long Term Debt	45.50%	10.50%	4.78%
Preferred Stock	11.50	10.08	1.16
Common Equity	43.00	16.00	6.88
Total	100.00%		12.82%

14.5 Interest Rate Balancing Account

SDG&E proposed the implementation of an interest rate balancing account as an experiment for 1984 and 1985 in order to automatically capture the volatility of interest rates. It claims the beauty of a balancing account is that it will capture the financial and operational realities of interest rate fluctuations for the benefit of both consumers and the company. SDG&E claims it is willing to forego the opportunity for any unanticipated benefits coming out of the current ratemaking process in exchange for protection against variations in interest rates which threaten the company's financial integrity. SDG&E claims this would be a two-way account benefiting the company and the ratepayers.

Witness Quan for the staff acknowledged that although SDG&E's proposal would operate for both the customers and the shareholders' benefit, he basically objected to the mechanism because it guarantees recovery of SDG&E's interest costs. The staff primarily opposes the balancing account idea because, in their view, it would reduce the incentive for the company to finance at the lowest cost and shelter it from all risks associated with changes in the general level of interest rates. When coupled with all the other balancing accounts which are in effect the proposal would be one more step in guaranteeing company profits during the test year.

We agree with the staff position. We are not convinced that the implementation of an interest rate balancing account is necessary or desirable at this time. As has been the case in most recent general rate case proceedings, the Commission allows for financial attrition by adopting a uniform capital structure for the test year and the attrition year and allowing for varying projections of debt and preferred stock costs over the two years. This is a reasonable means by which to recognize the impact of financial attrition in 1985. Accordingly, as recommended by the staff, we will continue to use this procedure to mitigate the impact of financial attrition on SDG&E.

Based on the adopted cost of long-term debt and preferred stock, the adopted allowance for financial attrition is set forth below:

6. Phase out present and reject proposed programs which, because of the potential for reduced billings, would probably be undertaken by participants without incentive payments.

7. Maintain or initiate programs which, although they may not meet some of the above objectives, are worthwhile based on considerations of equity such as the ability of low-income groups to participate, externalities, and irreducible factors not subject to precise economic measurement.

We will expect SDG&E and our staff to work closely during 1984 to effect the policy we have outlined above. Any problems with the program should be brought to our attention immediately through the advice letter filing procedure for our review and resolution.

15.1.11 Staff's Proposed Penalty Mechanism

As a result of questions from the ALJ concerning staff policy on proposed penalties for nonperformance in the conservation area, a staff witness attempted to develop a policy ad lib from the witness stand. We believe such a policy should be more carefully developed, particularly the provisions for rewards as well as penalties. The staff may wish to propose something in the 1986 rate case which can be considered by the Commission and the parties.

15.1.12 Company/Staff Relationships

Unfortunately this record shows what appears to be an adversary relationship between our conservation staff and SDG&E. We recognize that these situations will sometimes develop but they are usually ameliorated in a short time. However, in this case, SDG&E during the hearings and, in particular, in its brief at pp. 187-189, appears to be sounding a cry for help in curbing unnecessary and unauthorized staff interference. Our response is to instruct our Executive Director to review the matter with the principals and take what steps are necessary to develop a smooth working relationship between the two staffs in what we consider to be a very important area of regulatory review.

15.2 Conservation Measurement and Cost-Effectiveness

Most of the cost effectiveness analyses made for this proceeding are based on the recently issued joint report of our staff and the CEC staff entitled Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs by Danforth, Weiss, and Woychik. Although SDG&E did not base its tests strictly on the procedures outlined in the Standard Practice because it was not completed when it made its tests, it used procedures which were essentially similar to the staff's.

SDG&E used three tests to assess the cost-effectiveness of its conservation and load management programs: the participant test, the nonparticipant test, and the societal test. The participant test measures the costs and benefits of a program to ratepayers who use that program. The nonparticipant test measures the effect of a program on ratepayers who do not use the program but who do fund it. And the societal test measures the benefits of a program to society as a whole compared to the total cost to the utility of conducting the program.

Staff used the same three tests as SDG&E plus an additional test, the utility revenue requirement test. That test measures the effect of a program on the overall revenue requirement of the utility.

One of the factors in the formula for calculating the benefit/cost ratio in the nonparticipant test requires subtraction of the system average cost from the marginal cost. Normally this would indicate how much would be saved by eliminating a unit of power and not having to replace it at the marginal cost of energy. However, the nonparticipant test becomes meaningless for SDG&E because its average cost exceeds its marginal cost by a significant amount. Both SDG&E and the staff expect that phenomenon to continue well beyond the year 2000. Therefore, all programs failed the nonparticipant test automatically.

To sum up the other tests, all programs passed the participant test, meaning the participants would benefit from the program; no programs passed the nonparticipant test meaning that even though the nonparticipants paid for part of the program they received no benefits; all programs except the 8% and multi-family weatherization program and the energy information center program passed the societal test; and all programs tested passed the utlity revenue requirement test.

There is very little controversy between SDG&E and staff on how the conservation measurement and cost effectiveness tests should be made nor what basic figures, such as marginal costs, should be used to make the calculations. The differences, from a technical standpoint, are insignificant. Differences that exist are a result of how the tests should be used. SDG&E believes that if a program fails the nonparticipant test, it should be dropped regardless of the results of other tests. Staff takes the position that, although the nonparticipant test should certainly be considered, the Commission should also consider the other three tests in making its decisions on the desirability of programs. We will expect the tests to be used in the most practical way that serves the policies we have outlined in this decision.

15.3 <u>Residential Programs</u>

15.3.1 <u>Weatherization</u>

There are three programs under residential weatherization, 8% financing, direct weatherization assistance, and the multifamily program.

Loy recommends that SDG&E's proposed method be rejected because the staff cannot, in a timely manner, verify results from such an immense model. Without the ability to verify results, the Commission must be completely reliant on the integrity of applicant. Also, it makes it difficult for other parties to make recommendations in rate case proceedings. He believes this violates principles of fairness because estimating methods should be available to all parties for scrutiny. For these reasons, Loy recommends that SDG&E's proposed method be rejected as unacceptable for rate case proceedings and that the Commission adopt his MPPI method as being the most reasonable and fair.

Even though the DRI method has the infirmity of equal weighting at the subaccount level to which varying escalation factors are applied, we believe it more accurately reflects SDG&E experience. The staff's generalized method is basically a measure of the inflation present in overall industrial economic activity and, as staff indicated, can be used for either PG&E or SDG&E regardless of whether there are significant differences in their operational characteristics. Loy made no analysis of how the staff method compared with SDG&E's historical experience and agreed it would be difficult to test either the DRI or staff method against historical experience. Loy indicated that a choice between the SDG&E and staff method was pretty much of a tossup.

Although we are adopting the DRI method for this case, we would like to see the equal weighting of subaccounts replaced with appropriate SDG&E weightings. Contrary to the testimony of SDG&E, staff claims such records are available, at least in SDG&E's gas department.

We are not sympathetic with the staff charge that verification of the DRI method cannot be made in a timely manner because it is so complex. The business world is exploding with new computer technology. To reject SDG&E's effort because it is sophisticated and an attempt to keep up with new and innovative methods would be an unjust penalty for progressive management. We urge the staff to use the new tools available by developing its own expertise and using the new capabilities of the utilities by cooperative use of utility facilities through data requests.

5.1.2. Labor Escalation Factors

SDG&E uses DRI forecasts and its contracted wage agreements to estimate its labor escalation factors. SDG&E's original factors exceed the staff's estimates; however, SDG&E amended its factors to reflect more recent DRI-forecasts and, as Table 2 shows, SDG&E estimates for '84 and '85 are now below staff's. However, there is the issue of the staff policy recommendation that, for ratemaking purposes, wage increases should not exceed the increase in the cost of living as measured by the CPI-All Urban Index (CPI-U) under a baseline or neutral situation. To convince us of this, staff goes into a lengthy argument in its brief liberally sprinkled with citations to Commission and court decisions. While cost of living is an important factor in wage adjustments, Commission policy does not limit wage increase changes in the CPI. Utilities must have the flexibility to meet their skill requirements under conditions established by applicable labor markets. Nowhere, however, in testimony or argument does it present any evidence that SDG&E does not bargain effectively with its employees, within the framework of applicable labor markets. In fact, as shown on Table 3 which is taken from Page 2-2 of staff's Exhibit 24, for the latest five years of actual data, SDG&E has done quite well against the U.S. and San Diego CPI-Us.

TABLE 3

HISTORICAL PERCENTAGE CHANGES

	1978	1979	1980	1981	1982
United States CPI-U	7.7	11.3	13.5	19.3	6.0
San Diego CPI-U	9.9	16.5	15.1	13.4	7.0
SDG&E Wages	7.0	7.0	9.5	12.4	8.5

in 1981 and $137,000 in 1982. SDG&E claims that staff in making its estimate, did not apply an escalation factor. We will accept staff's method as being more reasonable. However, its estimate will be adjusted to include escalation factors adopted elsewhere in this decision.

5.17 Bank Fees (Account 930)

SDG&E normally keeps some excess funds on deposit in the bank to avoid transaction fees. Staff removed the excess funds from working cash allowance which is included in rate base, because staff calculated that payment of fees was a lesser cost alternative. Staff's approach attempts to minimize revenues for ratemaking purposes; it does this by arbitrarily removing two-thirds of the balance required to avoid all bank charges from rate base. In lieu, staff includes bank fees in administrative and general expense to replace the rate base deduction. SDG&E stipulated to staff's method but disagrees on what amount should be included for test year 1984. SDG&E estimates $556,200 and staff $411,000. The difference is primarily due to special escalation estimates developed for the account, SDG&E estimating a 35% rate and staff 15%. Staff's estimate is more reasonable and will be adopted.

5.18 Research, Development, and Demonstration (Account 930)

There is only a $35,400 difference between the company and staff for research, development, and demonstration. This difference involves SDG&E's request to fund an electric vehicle program. As expressed in our decision on Southern California Edison's request to fund an electric vehicle RD&D program, it is our policy to discourage utility expenditures on RD&D projects which promote increased demand for utility services (D.82-12-055 mimeo. p. 95). Therefore, we will adopt staff's RD&D expenditure levels which exclude the $35,400 for this program.

We find it is reasonable to direct SDG&E to comply with staff's recommendations that:

In future rate cases, SDG&E provide RD&D estimates in constant year dollars for labor vs. nonlabor and other.

SDG&E's future filings and April 15 annual RD&D report be in the format shown in Appendix D of staff's Exhibit 45 on RD&D including the information requested by staff on pages 2 and 3 of that exhibit, consistent with D.82-12-005.

We will authorize SDG&E to provide funding for the Electric Power Research Institute (EPRI) at the level established by EPRI's actual billing to SDG&E for 1983, which is $2,514,000. This is consistent with the treatment of EPRI expenses allowed for PG&E and SCE in recent general rate case decisions.

6. Electric Department Expenses

6.1 Boiler Plant Maintenance (Account 512)

Estimates for this account are SDG&E $5,631,800; Staff $4,764,600; difference $867,200.

The difference is due to two factors. Differences in forecasting methods accounts for a $747,200 difference in Subaccount 512.1 (Routine Boiler Maintenance); SDG&E's unforeseen expense factor accounts for a $120,000 difference in Subaccount 512.2 (Boiler Overhauls). The latter factor will not be allowed as we concluded in our discussion of unforeseen expenses. SDG&E used a 10-year trend in estimating Subaccount 512.1. SDG&E claims the units involved with the maintenance expense are 23 years old and the average age is increasing. In addition the units are subject to increased cycling, that is, starting and stopping the units for service, because SDG&E is diversifying its resources and using substantially increased amounts of nuclear and purchased power. SDG&E claims this increases the stress on the plants and leads to additional maintenance. Also, SDG&E states that the quality of oil burned in the units has been degrading and that also requires additional maintenance.

rate base for 58 months. Therefore, SDG&E allocated 58/196ths of the $2,375,116 to its utility operation.

A staff witness recommends that the entire gain on the sale be flowed through to ratepayers. He based his recommendation solely on an application of the uniform system of accounts. He stated that if a loss had been incurred, he would likewise recommend that loss be passed through to the ratepayers. Staff counsel in his brief argues that this Commission employes a risk of loss methodology in allocating gains from the sale of utility plant and sites. He gave D.82-12-121 in OII 82-05-01 dated December 30, 1982 as his authority. However, we note in that decision at page 23, the following:

> "We agree with the parties that risk analysis should be the major consideration underlying the allocation of the gain (or loss) between shareholders and ratepayers. While there are several Commission decisions that do apply this principle, each major abandonment problem should be reviewed on an individual basis. Therefore, we consider these other decisions informative but not dispositive of the way risk is shared."

There is no question on this record concerning the propriety of the Sorrento East Property in the rate base, that was decided in 1972 and in 1976. We will adopt San Diego's position but make a different calculation than the company. At RT 964, witness Honick agreed that had there been a rate case in 1966 when San Diego acquired the property, the Sorrento East Property would have been put in the rate base by SDG&E in its showing before the Commission. Therefore, we will add the time from 1966 to 1972 as time in rate base as well as the period from 1972 to 1976. We do this on the assumption that had ratepayers not been supporting Sorrento, SDG&E would have requested rate relief before 1972. This record does not show exactly how many months the property would have been in the rate base under that approach between 1966 and 1972; we will assume it would have been 6 years or 72 months. Adding the 72 to 58 used by SDG&E gives us 130; dividing 130 by 196, the total time the property was held by SDG&E, gives a percentage of 66.3%. When this is multiplied times the $2,375,116, we obtain a total applicable to ratepayers of $1,574,702; subtracting from that the $702,842 which has already been booked in 1982, gives $871,860 which we will book in 1984 and 1985. This treatment is similar to our treatment of the SONGS sleeving writeoff. Therefore, we will book $436,000 to electric revenue in 1984 and in the attrition year 1985.

14. Rate of Return

For 1982 and 1983 test years, the Commission granted SDG&E 12.92% and 13.25% rates of return. These included a return on equity of 16.25% and reflected incremental bond costs of 16% for 1982 and 14.5% for 1983, respectively. A significant development during the hearing phase of these proceedings was the upgrading of SDG&E's bonds in May and early June of 1983 from B+/Baa to A- rating. The company had as its long-term goal an upgrading sometime in 1984. Similarly, in making its determination for 1982 test year, the Commission assumed that "this goal cannot be achieved in 1982 or 1983" (D.59788 mimeo, P. 26).

There have been several changes in the recommendations on rate of return during the course of these hearings, including updates made at the hearing in September, 1983. In the company's NOI and application which were filed in the fall of 1982 and late December 1982, respectively, SDG&E asked for a rate of return of 14.93% in 1984 and 15.34% in 1985, with a requested return on equity of 19%. SDG&E estimated a cost of 16% and 15½% for new bond issues in 1984 and 1985, respectively. At the prehearing conference on February 3, 1983, SDG&E reduced its request to 14.05% overall and a 17.5% return on equity to reflect improved market conditions.

participating ratepayers, and this raises fundamental questions of equity and discrimination in the regulation of SDG&E. He sees the starting point for a regulatory conservation policy as an objective measure of cost-effectiveness which is equitable to all ratepayers. He maintains the non-participant test, such as that employed by SDG&E and the staff, and which we discuss later, can perform that function. Also, it is the only economically valid test which meets the regulatory standard of fair and reasonable rates. However, Neuner is aware that when a utility's marginal costs are less than its average costs the non-participant test will not show conservation measures to be cost-effective; he proposes that carefully considered programs should still be undertaken, particularly those of an informational nature.

In conclusion, Neuner recommends the program shown on Table 10.

Table 10

Neuner's Recommended Conservation, Load Management and Cogeneration Budget

Prior Year Commitments (SDG&E, Exh. #94)	$ 4,450,000
Cost-Effective Programs:	
Load Management (Staff, Exh. #102)	3,956,000
Conservation/Voltage Regulation (SDG&E & Staff)	58,000
Ancillary Activities (SDG&E & Staff)	1,201,000
	$ 5,215,000
Information-Oriented Customer Service Programs (SDG&E, Exh. #94)	4,486,000
	$14,151,000

15.1.10 Adopted Conservation Policy

We are persuaded by the arguments of SDG&E, City of San Diego and Neuner that it is time to make some cutback of expenditures for conservation. Each of the programs for which expenses are detailed on Exhibits 91 and 94 and summarized on Table 9 of this decision will be discussed in turn. But, as a general guide, our policy for SDG&E for 1984 and 1985 will be to phase down all programs, except load management, to the general level of SDG&E's recommendation in the last column of Table 9. For load management we will adopt a combination of the SDG&E and staff recommended levels of $5,469,200.

For revenue requirement purposes we will authorize for 1984 a level of expense approximately equal to that which would be required for the full year but, as the programs wind down, SDG&E will be expected to determine the amount of unspent funds and these can be refunded during the 1985 attrition year.

In addition to the general question of whether conservation programs produce fair and reasonable rates, our policy on conservation, load management, and cogeneration for SDG&E will be as follows:

1. Maintain and implement those programs which are required by law or governmental mandate.
2. Continue those programs required by past Commission decisions but review them to determine if they should be continued.
3. Maintain and implement those programs which provide conservation services needed by customers.
4. Implement only those new programs which are clearly shown to be cost-effective and, in particular, will avoid the need for additional future system generation capacity.
5. Phase out present and reject proposed programs which require incentive payments to participants borne by all ratepayers including nonparticipants but which are only cost-effective to the participants.

6. Phase out present and reject proposed programs which, because of the potential for reduced billings, would probably be undertaken by participants without incentive payments.

7. Maintain or initiate programs which, although they may not meet some of the above objectives, are worthwhile based on considerations of equity such as the ability of low-income groups to participate, externalities, and irreducible factors not subject to precise economic measurement.

We will expect SDG&E and our staff to work closely during 1984 to effect the policy we have outlined above. Any problems with the program should be brought to our attention immediately through the advice letter filing procedure for our review and resolution.

15.1.11 Staff's Proposed Penalty Mechanism

We believe that a policy on penalties for nonperformance in the conservation area should be more carefully developed, particularly the provisions for rewards as well as penalties. The staff may wish to propose something in the 1986 rate case which can be considered by the Commission and the parties.

15.2 Conservation Measurement and Cost-Effectiveness

Most of the cost effectiveness analyses made for this proceeding are based on the recently issued joint report of our staff and the CEC staff entitled Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs by Danforth, Weiss, and Woychik. Although SDG&E did not base its tests strictly on the procedures outlined in the Standard Practice because it was not completed when it made its tests, it used procedures which were essentially similar to the staff's.

SDG&E used three tests to assess the cost-effectiveness of its conservation and load management programs: the participant test, the nonparticipant test, and the societal test. The participant test measures the costs and benefits of a program to ratepayers who use that program. The nonparticipant test measures the effect of a program on ratepayers who do not use the program but who do fund it. And the societal test measures the benefits of a program to society as a whole compared to the total cost to the utility of conducting the program.

Staff used the same three tests as SDG&E plus an additional test, the utility revenue requirement test. That test measures the effect of a program on the overall revenue requirement of the utility.

One of the factors in the formula for calculating the benefit/cost ratio in the nonparticipant test requires subtraction of the system average cost from the marginal cost. Normally this would indicate how much would be saved by eliminating a unit of power and not having to replace it at the marginal cost of energy. However, at this time SDG&E's

For the 8% financing program, SDG&E recommends $2,785,200 to do 8,000 units and the staff recommends $1,234,200 to do 10,000 units, if the program is continued at its present level. The company recommends the program be deleted but that $474,100 be provided to continue support of the units already completed. There was a controversy, of course, on why the two estimates for continuation of the program were so far apart considering the number of units recommended for completion. The staff witness conceded that his estimate was tempered by his belief that SDG&E probably could not complete the units he recommends, so he cut his estimate for expenses accordingly. But that need not be settled because we will order the program to be phased down to the $474,100 support level recommended by the company by 1985. We will authorize $1,630,000 for 1984. That amount should support those units completed prior to 1984, and allow completion and support of an additional 3,300 units in 1984, which we set as the company goal for this program.

For the direct weatherization assistance (DWA) program SDG&E recommends 2,000 units for 1984 at a cost of $1,795,800 and the staff 4,000 for $2,000,000. Staff's lower cost per unit and larger number of units stems from its contention that there will be no start-up costs in 1984 and there are still over 12,000 units to be completed, therefore, 4,000 would be a reasonable goal. SDG&E disputes staff's estimates claiming that it is getting more costly to reach the low-income ratepayer because they are harder to sell even though the program is free, and there may not be any more than 8,000 units left to do. We believe this program needs a careful analysis using the policy criteria we have set up. We are inclined to favor a phase-out of the program as suggested by SDG&E but in the meantime will authorize the company $1,795,800 but set the goal at 2,500 units.

entirely as SDG&E recommends. As with the DWA program we would like to see a reevaluation based on our policy criteria; in the meantime we authorize the company estimate of $610,000. Assuming the staff's estimate has some validity, that amount should do considerably more than 500 units. We ask the staff and company to confer on this and come to a mutually agreeable number which can be approved as the goal for 1984 through our advice letter procedure.

15.3.2 Residential Audits

There are two programs involving audits, the residential conservation service (RCS) and swimming pools. Taking pools first, we will not fund the program in 1984. Pools are usually a luxury owned by the more affluent ratepayers; we expect the inverted block rate design to provide those customers with an incentive to conserve.

SDG&E estimates it can carry out the government-mandated RCS audits for $1,800,000 which is below the staff estimate and will be adopted.

15.3.3 Education

Three programs in this category are not significantly disputed by SDG&E and the staff, and consist of brochures, information centers, and consumer counseling. The company proposes a minor change in emphasis for these programs which we will adopt. The authorized expenses will be $400,000, $155,000, and $131,600 respectively.

For the meter conversion program which converts master meter gas and electric meters to individual meters in multifamily units, the staff recommends taking $382,000 from the RCS program to significantly accelerate the program in conjunction with audits. the idea would be to make the end-user aware of usage and therefore more likely to conserve. A $50 per meter rebate would be given to the landlord as an incentive to convert. The total cost of the staff program would be $461,000. SDG&E recommends the program be discontinued, but, if it is continued, 2,900 units be done at a cost of $79,000. We will fund the company proposal for 1984 but the program should be phased out by the end of 1984.

Both SDG&E and the staff recommend $15,000 for the pilot light reminder program, if it is continued. The company recommends the program be discontinued, however. This is a program which obviously meets our seventh criterion (Section 15.1.10) and should be continued.

SDG&E and staff both recommend $129,000 for the peak reduction program. The company further recommends, however, that it be discontinued. There are no clear benefits from the program on this record and it will not be funded.

Staff recommends four new programs in addition to the accelerated meter conversion. "Pull the plug" would be directed at homes which are not continuously occupied. Owners would be urged to turn off all power not necessary during absences. "One warm room" involves turning off central heating and using portable heaters to warm only the room or rooms being used. The "refrigerator replacement" program would offer rebates to ratepayers who replace their refrigerators with more efficient units. And a "water heater replacement" program which would be similar to the refrigerator program. None of these were shown by the staff in the evidentiary record to be cost-effective and they will not be adopted. The refrigerator and water heater programs are particularly good examples of programs that would be difficult to participate in by low-income ratepayers.

15.4 Commercial/Industrial

The major programs under this category are non-residential audits and conservation assistance. Both SDG&E and staff recommend total expenditures including cogeneration for commercial/industrial of $6,435,300 although again, the company recommends severe reductions in the program down to a figure of under $2,000,000. The major part of the $2,000,000 would be $1,639,200 for mandated audits. We are not sympathetic with expenditures for business conservation which cannot be shown to be cost-effective and these have not been. Therefore, we will adopt the company's recommendation for audits plus $78,000 for agricultural conservation and $56,700 for street lighting with no allowance for the conservation assistance and new business programs.

15.5 Solar

There is little difference between staff and SDG&E on the cost of the solar rebate program. We will adopt the staff estimate of $3,891,100. The other solar program is a project designed to assist builders and is primarily educational. SDG&E recommends the program be discontinued. We agree. We cannot imagine why reputable builders (most likely contractors) would not be aware of solar energy alternatives.

15.6 Conservatiuon Voltage Regulation

This is probably the one program everyone agrees is needed. SDG&E and staff agree on the cost, $57,600. It will be adopted.

15.7 Ancillary Expenses

Certain additional expenses are incurred by SDG&E for conservation activities which are not directly allocable to specific programs. These include general costs for buildings and services, advertising, management, and market research. Both SDG&E and staff recommend $2,876,400 for this expense, but under the reduced program recommended by SDG&E they would spend only $1,201,400. The record does not show how much of the reduction is due to an overhead reduction and how much to a direct reduction in activities such as market research. We will authorize the higher figure but expect SDG&E to account for any reduction it makes as a result of the modified program we are authorizing and make an appropriate refund in the 1985 attrition year.

16. Cogeneration

Both SDG&E and staff recommend $225,300 for cogeneration activities which will be adopted.

16.1 Staff's Proposed Penalty

The only issue in the cogeneration budget area is staff's recommendation that SDG&E be penalized 30 basis points on its electric department rate of return, approximately $2.6 million, for activities staff claims have discouraged the development of alternative customer generation in SDG&E's service territory.

Staff bases its recommendation on four sub-issues, a comparison of SDG&E's efforts in the cogeneration field with that of PG&E, complaints about the company's cogeneration program, a deliberate and unnecessary lowering of its payment rates to qualifying facilities (QFs), and unnecessary insurance requirements for QFs.

Comparing the efforts of SDG&E to PG&E the staff concluded that PG&E has acquired 2½ times more capacity than SDG&E and SDG&E has eight times more inactive projects than PG&E. Staff's calculations take into account the relative size of the two utilities. SDG&E countered the staff contention with evidence that the territories served by the two utilities are quite different. SDG&E does not have the industrial, oil refining, and large

17.2 Level of Activities

Load management standards are generally established by the Energy Commission. As previously cited under Section 15.1.5 of this decision the CEC has issued an order which requires SDG&E to install up to 8,000 central air conditioner cutoff switches in each of the years 1984 and 1985. CEC also ordered SDG&E to continue its water heater cycling experiment and, if cost-effectiveness is demonstrated, expand the program to install up to 6,000 switches in each of the years 1984 and 1985. The operative words which have caused a dispute between our staff and the CEC representative in these proceedings are "up to." There seems no question that some liberties can be taken with the water heater switch requirement but the 8,000 air conditioner switches means at least 8,000, claims CEC, less any that might be recycled for installation in second locations. SDG&E interprets the 8,000 as a requirement, our staff does not. We think the simple way out is to authorize enough for the 8,000, subject to refund and if the funds are not used and if the company does not install 8,000 it is between it and CEC. Therefore, we will adopt the SDG&E recommended amount for air conditioners and the staff's for water heaters. The other expenses proposed by SDG&E appear to be reasonable and, subject to the same refund conditions we put in the last rate case, will be adopted. The total load management budget authorized will be $5,469,200.

18. Adopted Budget for Conservation, Cogeneration, and Load Management

Based on the foregoing discussion, Table 11 is a summary of our adopted maximum budget for conservation, cogeneration, and load management. The present limitations and procedures for shifting funds between programs will continue in effect.

demand charges have been paid, there is less incentive for users to conserve because the average cost of electricity per kWh keeps decreasing as usage increases. Staff believes that the more one puts on the per kWh energy cost the greater the incentive for customers to cut their usage. SDG&E claims that its energy costs are so high now that there is ample reason for customers to conserve and moving some of the demand charge to the energy charge will not help.

Rock Producers supports the staff position that what customers see as they conserve when a demand charge is present is a rise in their average bill in terms of cents per kilowatt-hour. This is just the opposite of what the customers should see, claims Rock Producers. It also contends that most of the demand charges are probably based on short periods during the month when users have all their facilities running. Thus, when they take steps to conserve, the demand charge remains the same regardless of how much energy is conserved and the average charge can become ridiculously high.

We do not agree with the staff or Rock Producers that demand charges serve to stifle conservation because of their effect on the average cost of electricity. SDG&E's energy rates are among the highest in the nation and no further augmentation is needed through a reduction in the demand charges. We believe the demand charge has a significant purpose in the overall scheme to reduce system peak demand. We adopt SDG&E's proposal.

24.2 Minimum Charges

Staff opposes the continuation of "demand ratchets" in the application of the minimum charge provisions of the AD, AL-TOU, and A6-TOU schedules. For instance, the Schedule AD minimum charge provision is as follows:

> "The minimum charge shall be $2.00 per kilowatt of the highest Maximum Demand during the preceding 11 months."

One can see that the maximum demand can "ratchet" up and down from billing period to billing period. Staff testified that the demand-ratchet provisions no longer exist for any of California's major

24.3 Minimum Demand Charge - Schedule AD

There is a minimum demand charge in Schedule AD which requires customers to pay $90 per month for the first 20 kilowatts or less of billing demand, with a charge of $4 for each kW over 20. SDG&E proposes to raise these charges to $110 for the first 20 kWs or less and $5 for each kW over 20. Staff proposes elimination of the charge altogether. SDG&E opposes staff but would alter its proposal to $90 for 16 kW or less and $5 for each kW over 16. SDG&E claims this will give the smaller customers more of an incentive to control their demand without giving them a price signal to increase consumption. We will adopt SDG&E's alternate proposal.

24.4 Eligibility for Schedule AD

Schedule AD is applicable to customers whose monthly maximum demand exceeds 20 kW or whose average consumption exceeds 4,800 kWh. Staff recommends AD be modified so that customers are eligible regardless of their consumption level. This would open the schedule to any customer whose demand is in excess of 20 kW.

SDG&E points out that it could not determine whether a customer was eligible without first installing a demand meter for the customer. SDG&E claims this could mean installing meters on all Schedule A customers to determine if they met the requirement, a prohibitively expensive proposition. However, if the 4,800 kWh requirement is eliminated, as staff proposes, the only additional metering required would be for customers who use in excess of 20 kW. These are the customers who should be on Schedule AD anyway. The staff's recommendation will be adopted.