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Decision 89 11 088 NOV 22 1989

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) for authorization to establish its cost of capital for 1990.

Application 89-05-011
(Filed May 8, 1989)

Application 89-05-019
(Filed May 8, 1989)

Application 89-05-021
(Filed May 8, 1989)

Application 89-05-023
(Filed May 8, 1989)

Application 89-05-037
(Filed May 17, 1989)

Application 89-06-015
(Filed June 15, 1989)

And Related Matters.

(See Appendix A in Decision 89-08-034 for appearances.)

Additional Appearances

James D. Salo, Attorney at Law, for Sierra Pacific Power Company, applicant.
Deborah L. Berger, for City of San Diego, and Chester and Schmidt Consultants, by Reed V. Schmidt, for California City and County Street Light Association; interested parties.

I N D E X

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O P I N I O N

I. Summary of Decision

Today's order establishes the 1990 ratemaking cost of capital for Southern California Gas Company (SoCalGas), Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), San Diego Gas & Electric Company (SDG&E), Southwest Gas Corporation (Southwest), and Sierra Pacific Power Company (SPPC). The rates of return on rate base authorized by this decision will be reflected in 1990 attrition filings of Edison, SDG&E, and Southwest, and will be incorporated in the 1990 test year rates for SoCalGas, PG&E, and SPPC, whose general rate cases are pending.

We conclude that for 1990, the energy utilities should be authorized returns on common equity and overall returns on rate base as follows:

Utility	Common Equity	Rate Base
SoCalGas	13.00%	10.75%
PG&E	12.90	10.96
Edison	12.85	10.70
SDG&E	12.90	10.86
Southwest	13.05	11.63
SPPC	13.00	10.34

II. Procedural Background

By Decision (D.) 89-01-040 dated January 27, 1989, we modified the Rate Case Plan for energy and telecommunication utilities. One of our objectives in doing so was to reduce the complexity of processing general rate cases at the end of each calendar year. As part of the modifications, we removed consideration of cost of capital issues from general rate cases involving seven designated gas and electric utilities (SoCalGas, PG&E, Edison, SDG&E, Southwest, SPPC, and Pacific Power & Light

Company) and established a separate, generic, annual cost of capital (ACC) proceeding.

Beginning with May 8, 1989 and continuing on the same date in subsequent years, each of these utilities is required to file an application for rate adjustments which reflect its projected cost of capital for the following year. The plan provides that the new rates will be implemented on January 1 in conjunction with the utility's pending general rate case or its attrition rate adjustment filing as applicable. Although we have since 1986 conducted annual reviews of return on equity issues in consolidated "financial attrition" proceedings, this is the first ACC proceeding under the modified Rate Case Plan in which the cost of capital of each of the utilities is reviewed, including those with pending general rate cases.

In accordance with the modified Rate Case Plan, SoCalGas, PG&E, Edison, SDG&E, Southwest, and SPPC filed Applications (A.) 89-05-011, A.89-05-019, A.89-05-021, A.89-05-023, A.89-05-037, and A.89-06-015 respectively. By A.89-05-017, Pacific Power & Light Company requested an exemption from participation in the 1989 ACC proceeding. That request was granted by D.89-08-034 dated August 3, 1989. The remaining applications were consolidated for hearings which were held before Administrative Law Judge (ALJ) Wetzell during August 1989. Testimony and evidence was presented on behalf of the six applicants as well as the City of Los Angeles (Los Angeles), the Department of the Navy representing all Federal Executive Agencies (FEA), and the Division of Ratepayer Advocates (DRA). While they did not present testimony or evidence, the City of San Diego and Edward Duncan actively participated in the hearings by cross-examination of witnesses and, in the case of San Diego, by briefing. The matters were submitted with the filing of reply briefs on September 20, 1989.

III. Generic Issues

Although we have established a generic annual proceeding to consider the cost of capital for energy utilities, it is not necessarily our intention to establish a uniform rate of return on rate base or return on equity which would be applied to each utility, without regard to differences among them. Therefore, in subsequent sections, we consider factors that are unique to each of the applicants and determine the appropriate capital cost factors which should be adopted for each utility on a case-by-case basis. In this section we address common issues which warrant general discussion.

A. Trigger Mechanism

In D.89-01-040, by which we modified the Rate Case Plan and established the ACC proceeding, we had considered a DRA recommendation to consider return on equity adjustments only in general rate cases or when a predetermined index changes by more than a preset amount. We agreed the recommendation had merit, but were reluctant to adopt it without a more complete record. We invited parties interested in pursuing the use of such a trigger mechanism to address this matter in a future annual cost of capital proceeding. SoCalGas, PG&E and DRA addressed the trigger mechanism concept in this proceeding.

SoCalGas points to our discussion of energy utility attrition proceedings in D.85-12-076, where we stated:

> "In our attrition reviews, we need to recognize the volatility and unpredictability of interest rates by incorporating a complete review of authorized rates of return, including an updated financing plan and forecast of new debt and preferred stock costs, as well as reevaluation of return on equity."
> (D.85-12-076, page 25.)

SoCalGas is concerned that a trigger mechanism would not allow such a full review unless selected financial data change by

more than a predetermined magnitude. SoCalGas believes that it would be extremely difficult to develop a workable and acceptable mechanism. For example, if only interest rates are used, changes in such factors as company-specific and industry-wide business risk would not trigger a review. Due to gas industry restructuring, SoCalGas states this could be a fatal flaw. SoCalGas points out that there is an alternative to a trigger mechanism: in years where parties agree that a full return on equity review is not required, a stipulation to that effect can be reached.

PG&E and DRA believe there may be merit to a trigger mechanism for return on equity. PG&E is willing to explore the issue in future workshops. DRA agrees with SoCalGas that there may be difficulties with simplified trigger benchmarks such as interest rates, and suggests that the issue needs further research.

No party recommends implementation of a trigger mechanism at this time. After we have gained more experience with our recently revised ACC procedures, we will be in a better position to determine whether limiting the frequency of cost of capital filings is either necessary or desirable, and if so, whether stipulations have proven to be a workable alternative as SoCalGas suggests. If it appears at a future date that implementation of a trigger mechanism has merit, parties interested in pursuing the concept may still address the matter in future proceedings.

B. Recovery of Premiums Paid to Retire High Cost Debt

In the last financial attrition proceeding (A.88-07-023, et al.), we addressed the methods that utilities were using to treat the tax savings created by the deductibility of the call premiums paid to bondholders when high-cost debt is prematurely retired. DRA had raised the issue in that proceeding because the utilities were using different methods to pass the tax savings back to ratepayers, and in some cases were not reflecting any tax savings in deferred tax reserve. While it recommended that the savings be passed back to ratepayers, DRA did not propose a

specific method for doing so, proposing instead that the issue be addressed in workshops.

By D.88-12-094 in that proceeding, we directed the Commission Advisory and Compliance Division (CACD) to conduct workshops on the issue for the purpose of establishing a consistent method to pass the tax benefits back to the ratepayers. We directed SoCalGas, PG&E, Edison, SDG&E, SPPC, and DRA to address the results of the workshops in the next financial attrition proceeding. (Southwest was not included in that directive since it had a general rate case pending and was not a party to the previous cost of capital proceeding).

The workshops were held in March and April of 1989. The participating utilities and DRA agreed in principle on using the "Modified PG&E Method 2" (workshop method) by which they will record the call premiums at the combined federal and state tax rates in the year of refunding, with full amortization of the premiums and related expenses within a specified period using the straight-line method. CACD's report describing the workshop method was issued after the ACC filing date of May 8, 1989, and most of the utilities therefore did not reflect the workshop method in their showings accompanying the applications.

DRA prepared a comparison showing the impact of the workshop method on the estimated effective costs of long-term debt. The workshop method results in a lower long-term debt cost for each of the energy utilities. The following table shows DRA's comparison, which reflects forecasted bond yields in effect when DRA prepared its testimony:

Long-Term Debt Costs

Utility	Workshop Method	Existing Method
SoCalGas	9.45%	9.58%
PG&E	9.29	9.33
Edison	8.93	9.29
SDG&E	9.20	9.40
Southwest	10.56	11.19
SPPC	8.71	8.85

DRA recommends that the workshop method be adopted and incorporated in the authorized rates of return for 1990, and each of the applicant utilities has either incorporated the method in an updated showing or accepted DRA's calculation of embedded debt costs. The City of Los Angeles incorporated the workshop method in its showing on SoCalGas' cost of capital. As there is no dispute on the workshop method, we will adopt its use for determining the cost of long-term debt.

C. Spread Between A and AA Bond Yields

DRA and Los Angeles dispute the cost estimates advanced by SoCalGas, PG&E, and SDG&E for new long-term debt issues, primarily because they disagree on the appropriate premium to be added to the Data Resources, Inc. (DRI) forecast of AA rated utility debt when estimating the cost of issues by utilities with lower bond ratings.

In D.85-12-076 we established new criteria and procedures to be followed in attrition filings by the energy utilities, including a method for updating the embedded cost of debt by considering both the actually incurred costs of recent debt issues and the forecasted costs of planned new issues. For the forecasted costs, we directed utilities to use the DRI forecast for AA rated utility debt, and indicated that "[u]tilities that do not have both an Aa (Moody's) and AA (S&P's) rating should add a risk premium of no more than 50 basis points if appropriate." (D.85-12-076, page 31; emphasis added.)

DRA, Los Angeles, and FEA believe that while the 50 basis point spread may have been appropriate at the time it was adopted, it is not reflective of the current spread between A and AA rated issues and should be adjusted downward. Using data from Moody's bond survey, DRA prepared an analysis showing that in the past 12 months (July 1988 to June 1989), the average spread was approximately 20 basis points. This compares with declining average premiums of 48, 32, and 29 basis points over the last 10-,

five-, and three-year periods, respectively. DRA's witness Quan also testified that a utility with an A rating will not necessarily incur debt costs as high as the single A rate for all issues. Based on its analysis, DRA recommends additives of 25 basis points for SoCalGas and PG&E and 15 basis points for SDG&E.

Los Angeles presented a similar analysis showing that the average differential for the five-year period 1979-83 was 63 basis points. The median differential was 46 basis points. For the five-period 1984-88 the average differential was 32 basis points and the median was 28 basis points. In 1988 the average differential was 23 basis points and the median was 24 basis points.

Los Angeles presented a separate analysis showing that the offering yields and effective interest rates on six SoCalGas bond issues in 1986 and 1988 were, on average, actually lower than contemporaneous Moody's Aa utility bond yields. Los Angeles concludes that there is no basis for a 50 basis point additive, and that the evidence suggests that no additive is required in estimating SoCalGas' cost of new issues in 1989-90.

SoCalGas and PG&E, whose bond ratings are A1/A+ and A1/A, respectively, added a 50 basis point risk premium to the DRI forecast to estimate the cost of new debt issues. SoCalGas also used the 50 basis point additive to develop its forecast for a planned preferred stock issue. SDG&E, with a bond rating of Aa3/A+, used a 35 basis point additive, which is one half of the average spread between A and AA bonds computed by SDG&E for the period 1982 to 1988.

The utilities acknowledge that the spread between A and AA rated bond issues has narrowed in recent years, but believe that DRA's recommended spreads are too conservative and, further, urge that we look at longer-term data than that relied on by DRA in its recommendation. SoCalGas lowered its recommended spread to 30

basis points for 1990, which is close to the most recent three-year average of 29 basis points calculated by DRA.

PG&E argues on brief that short-term economic data such as one year's worth of information are of limited value given the uncertainty of capital markets, and recommends using three- to 10-year data and a resulting spread of 30 to 50 basis points. At the same time, PG&E also urges that we consider the increase in the spread (to 27 basis points) in the four-month period between February and June of 1989 as demonstrative that DRA's recommendation is too conservative. SDG&E recommends additional review of the spreads that are current at the time we reach a decision in this matter.

It appears to us that the utilities are placing too much emphasis on the possibility that the clear trend of declining spreads in recent years has bottomed out and will rise significantly in late 1989 and 1990, and not enough emphasis on the possibility that the trend of declining spreads shown in DRA's and Los Angeles' analysis will either continue downward or stabilize at or near current levels. We note that in the first six months of 1989, the differential ranged from 14 to 27 basis points, and in five of those months the differential was the same as or less than that of the corresponding month in the previous year.

We find that DRA's recommendation of 25 basis points for PG&E and SoCalGas is reasonably conservative in that it is five basis points above the most recent 12-month average spread of 20 basis points, and slightly above the 1988 calendar year average. On the other hand, we do not believe that Los Angeles' suggestion that there be no additive for SoCalGas in 1990 is reasonable for forecast purposes. We find that DRA's recommendations are reasonable for 1990.

DRA notes that there will be an opportunity to reevaluate the appropriate spread in one year since we have established an annual cost of capital review for all energy utilities, and

SoCalGas recommends such a review in each year's ACC proceeding. We agree that it is appropriate to do so in ACC proceedings.

D. Interest Rates

1. Background

We have frequently expressed our view of the importance of interest rates in determining cost of capital issues, particularly return on equity. For example, in deciding Edison's 1988 test year general rate case, we stated the following:

> "In recent general rate cases for the large electric utilities, we have indicated that a utility should be authorized a return on common equity (ROE) that is commensurate with market returns on investments having corresponding risks. We also have repeatedly stated that there are three considerations which we rely upon to implement this objective:
>
> "1. Cost of capital varies in the same direction as changes in the general level of inflation and interest rates.
>
> "2. Market cost of equity capital reflects risks, such as the exposure of a utility's earnings to variability in fuel costs, sales levels, as well as uncertainties regarding the cost of prior capital investments.
>
> "3. The application and interpretation of financial models may not accurately reflect all of the intricacies of the financial market.
>
> "In evaluating the proposals before us...we will place heavy emphasis on these principles. (D.87-12-066, page 42.)

All of the parties were mindful of the importance we place on interest rate trends in deciding a utility's cost of capital, and much of the controversy in this proceeding related to their views on the overall direction of interest rates. The

parties agree that actual and forecasted interest rates have declined in recent months, and the utilities, to varying degrees, acknowledge that the lower interest rates in effect and forecasted at the time of the hearings support returns on equity lower than those requested in their applications.

The major interest rate issues are the reliability of available forecasts, particularly DRI's forecasts for utility bonds, and whether forecasts for late 1989 and 1990 only should be considered to the exclusion of longer-term forecasts. A detailed description of the parties' positions follows.

2. Position of the Utilities

SoCalGas, PG&E, Edison, and SDG&E generally agree on the interest rate issues. They argue that the DRI Control forecast for AA utility bonds is suspect and should therefore be used with caution in this proceeding, and other interest rate forecasts are also too uncertain to use with confidence in making precise return on equity recommendations. In particular, the utilities maintain that the current level of lower interest rates does not support the contention that equity investors' required returns have fallen substantially. They believe the DRI forecast should be considered only in conjunction with other forecasts and current rates. The evidence and arguments are summarized below:

1. The approximate 130 basis point decline from the April forecast of 9.96% to the July forecast of 8.67 and the September forecast of 8.64% for 1990 demonstrates the uncertainty associated with the DRI forecast.

2. The DRI Control forecast for AA bonds is at odds with the July Wharton Economic Forecasting Associates (WEFA) forecast of 9.8% for 1990. DRI's July 1989 Control forecast in 1990 is 153 basis points less than its Late Recession forecast.

3. Interest rate forecasts by PG&E, DRI, WEFA, and Meyer generally show interest rates reaching a peak in early 1989, declining

temporarily in mid-to-late 1990, and then increasing again in 1991. However, these forecasts assume a recession or a slowing of economic growth, and no federal action to keep interest rates from dropping, making them increasingly unlikely.

4. The DRI forecast is inconsistent with the historical relationship between AA utility bonds and inflation rates. Since 1981 the yield on AA utility bonds has averaged 7.6% greater than year to year changes in the consumer price index (CPI). In 1987 and 1988 the yield was 5.5% greater than the CPI. The DRI forecast for AA utility bonds is only 4.3% greater than the forecasted inflation rate for 1990. Premiums as low as 4.3% have not prevailed since 1970.

5. By D.88-12-094 in the previous energy utility cost of capital proceeding, the Commission chose to place greater reliance on recorded interest rates and less reliance on the DRI forecast due to the subjective analysis underlying the DRI forecast and the history of variations up to 181 basis points between the forecast and actual rates. While recorded rates declined from the January 1989 level to 9.23% in July 1989 the decline is not as great as the DRI forecast.

6. Variations in recorded AA utility bond rates of more than 800 basis points during the past seven years and over 175 basis points during the past two years highlights the uncertainty associated with forecasting interest rates.

7. Other economic indicators do not support the DRI outlook. For example, PG&E notes that while A-rated utility bonds increased in the first quarter of 1989 then decreased, the prime rate and the discount rate increased since mid-1988.

8. The Commission should place less reliance on interest rate forecasts than it has in previous years because capital markets are currently volatile and uncertain, with

> stock prices and bond yields fluctuating 20 to 30 basis points within a few days. Interest rates can change by more than a hundred basis points in a matter of months. DRI's forecasts of three-month Treasury Bills vary by as much as 217 basis points in the second quarter of 1990.
>
> 9. DRI is terminating its AA interest forecasts at the end of this year.

Even if there is a short-term decline in interest rates in 1990, the utilities argue that equity investors are concerned with the value of a security over time, and temporary interest rate downturns will not change their return requirement. Thus, the utilities believe it is important to evaluate more than a single year's forecast in setting a return on equity.

3. DRA

Acknowledging that forecasts should be used with caution in estimating cost of capital, DRA recommends consideration of current interest rates as well as forecasts in deciding a reasonable return on equity. Long-term 30-year Treasury Bonds remained relatively flat in the first five months of 1989 then began to fall in the middle of May through July. Short-term three-month Treasury Bills rose from the beginning of the year through March, then began to decline in March through July. DRA believes that Federal Reserve Board actions to reduce the federal funds rate and reductions in the prime rate in June are consistent with an economic slowdown.

In DRA's view, inflation has stabilized and interest rates are likely to decline through 1990, as shown by the DRI forecast. DRA concludes that economic conditions today, and those forecasted for 1990, reflect an environment of lower interest rates than those considered in last year's cost of capital proceeding. DRA maintains that investors will consider this relatively stable environment when investing in various instruments over the long-term.

DRA believes that investors will also take into consideration the fact that the Commission now sets a rate of return each year, and will therefore expect returns which reflect then-current economic conditions in each future period. While investors expectations about interest rates in 1991 should be considered, the main concern, DRA argues, is for 1990. DRA believes this is consistent with our previously-stated principle that the cost of capital varies in the same direction as changes in the general level of inflation and interest rates.

4. Los Angeles

Los Angeles presented testimony comparing inflation and interest rates at the time of hearings and decision in the previous financial attrition proceeding with current levels as of late July 1989. Los Angeles concludes that while short-term interest rates have risen, there has been a marked decline of 75 to 100 basis points in long-term rates. Los Angeles also presented testimony citing a survey of 38 well-known economists concluding that for the remainder of 1989 and 1990 the economy would experience slow growth, and there would be no recession, little change in bond yields, lower short-term interest rates, and lower inflation.

Los Angeles believes that inflation and interest rates are key determinants of a proper return on equity, and concludes that the above-described reductions in inflation and interest rates since last year's cost of capital proceeding are significant and must be reflected in a meaningful reduction in SoCalGas' currently authorized return on equity.

5. City of San Diego

The City of San Diego notes that the July 1989 DRI Control AA utility bond forecast is approximately 8.7%, while the April forecast used by SDG&E in its financial model analysis is approximately 10.0%. According to the City, substituting the July for the April forecast in the analysis results in a lower range of

estimated returns on equity that is consistent with DRA's recommendations.

The City of San Diego takes issue with the utility position that the DRI Control forecast should be discounted in setting equity returns. The City suggests that the utility witnesses may have applied their judgement in deciding to do so after it became apparent that use of the DRI forecast would be disadvantageous to the utilities.

In response to the utility testimony that historical variations between DRI-forecasted and later-realized actual utility bond rates demonstrate the unreliability of the DRI forecast, the City notes that the variations have been both positive and negative. Since the Commission sets returns on equity on the principle that such returns move in the same direction as interest rates, the City argues that the principle should apply for both upward and downward movements. As to the utility argument that the Commission should take a long-term view of interest rate trends in setting equity returns, the City supports DRA's view that investors are aware the Commission sets returns annually and therefore are primarily concerned with near-term rates.

6. FEA

FEA takes a position similar to that of the City of San Diego, suggesting that the criticism of DRI's Control forecast is based more on circumstance than it is on principle. While acknowledging that there are valid criticisms of the DRI forecast, FEA believes that the evidence in this proceeding indicates there is good reason to believe that interest rates in 1990 will be lower than they were expected to be in April 1989. FEA presented testimony showing that interest rates declined 60 to 110 basis points between December 1988 and late-July 1989. FEA believes its recommendations of lower returns on equity than those now authorized for SoCalGas, PG&E, Edison, and SDG&E are consistent with these declines.

FEA recommends a reevaluation of the use of interest rate forecasts in cost of capital proceedings. One alternative would be to use the most recently available information on actual AA bond rates at the time a decision is reached. FEA notes that over the last five years, this method would have resulted in an average error of 1.45% compared to the average error of 1.64% which occurred using the DRI forecast.

7. Discussion

We note at the outset that the use of the DRI forecast in calculating long-term debt cost is in accordance with the procedure we established in D.85-12-076 for financial attrition filings. At the same time, we reiterate our finding in last year's cost of capital proceeding that DRI's forecast is subjective and subject to variations, and that greater reliance should be placed on other factors in determining returns on equity.

While we agree there are shortcomings in the DRI Control Forecast, we don't believe that these shortcomings merit rejecting the forecast entirely. The fact that the forecast declined 130 basis points from April to July does affirm our concern with the forecast's reliability. It does not mean, however, that we will disregard the forecast in our determination of the proper return or equity.

Similarly, the fact that the control forecast is substantially below the Late-Recession forecast does not indicate to us that the Control forecast should be largely or completely disregarded. We note that DRI assigns a higher probability to the Control forecast than to the Late-Recession scenario.

We are not prepared to completely eliminate the use of interest forecasts in this proceeding as has been suggested. The argument that large variations in recorded AA utility bond yields

of more than 800 basis points in seven years and 175 basis points in two years undermines the forecasts is weakened for two reasons. First, as discussed below, our primary concern is the level of interest rates in 1990. We are less concerned about the magnitude of changes that can be expected to occur over periods of two or more years.

Second, we find fault with the analysis underlying the argument. The 800 basis point differential is the difference between the 16.78% yield in the first quarter of 1982 and the 8.56% yield in the second quarter of 1986. The 175 basis point differential is based on the 10.35% yield in the third quarter of 1988 and the 8.59% yield in the first quarter of 1987. (Exhibit 17, Table 2.) Since we are concerned with setting rates of return for a one year period, we think that yearly variations are of more value than variations measured on a quarterly basis when analyzing the magnitude of changes over time. We note that the differentials are smaller when yearly data are used. The 1986 yield is approximately 550 basis points less than the 1982 yield, and the 1988 yield is 49 basis points above the 1987 yield. (Exhibit 34, Table 1.) We find little basis in the record for concluding that AA utility bond rates are so volatile that predictions about them for the coming year are useless.

We conclude that while there is uncertainty associated with forecasting economic trends, interest rates are currently below the levels prevailing when we adopted the energy utilities' cost of capital for 1989, and are reasonably likely to remain below those levels during 1990. This conclusion is based not only on the DRI Control forecast, but on a variety of indicators which include alternative forecasts, current yields on Treasury issues and current utility bond interest rates, Federal Reserve Board actions to reduce the federal funds rate which are consistent with an economic slowdown, indications that inflation rates have been and will be lower than when we last considered the energy utilities'

cost of capital, and a survey of economists indicating an expectation of conditions which are consistent with lower interest rates.

Although there are several economic expectations which would indicate lower interest rates in 1990, we also must consider the reliability of these expectations.

By their very nature, expectations and forecasts are uncertain. The DRI forecast is substantially at odds with forecasts of other reputable institutions. For example, the July 1989 Wharton Economics Forecasting Associates (WEFA) forecast for AA bonds for 1990 is approximately 9.8 percent. Thus, the WEFA forecast is over 110 basis points higher than the DRI forecast for yields on AA utility bonds. This difference buttresses our concerns with basing conclusions heavily on forecasts and expectations.

We concur with DRA that in evaluating the relationship between interest rates and returns on equity, the main concern should be interest rates that are expected to prevail during the year for which rates are being set. While equity investors are concerned with the overall return over the entire period they hold the stock, we concur with DRA that investors will take into account the fact that returns on equity are regularly adjusted to reflect current economic conditions. The logical extension of the utility argument for considering long-term interest trends would be to set constant returns on equity that reflect long-term averages and do not vary with changes in economic conditions. As we noted earlier in our discussion of trigger mechanisms, we conduct annual cost of capital reviews in large part to recognize the volatility and unpredictability of interest rates.

While we believe that a climate of reduced interest rates indicates that lower returns on equity are required in 1990 (holding risks and other factors affecting returns constant), we agree with the utilities that forecasted reductions in bond rates

or any other single indicator cannot be used mechanically to lower equity returns with pinpoint precision. Moreover, given the degree of uncertainty we believe is reasonable to ascribe to the forecasts, we conclude that reductions in authorized returns on equity from current levels in the 70 to 90 basis point range recommended by DRA and FEA are excessive, on the basis of interest rate declines. On the other hand, all of the applicant utilities have requested increases in their authorized returns on equity ranging from 25 to 100 basis points. We find no support for such increases on the basis of interest rate trends demonstrated in this record. In our judgment, to the extent that interest rates are determinative of the proper return on equity, reductions in the

currently authorized returns in the range of 10 to 20 basis points are reasonable. We will consider such reductions along with business and financial risks and other factors in determining the authorized return on equity for each utility.

As previously noted, our current procedures provide for use of the DRI Control forecast in calculating the cost of long-term debt. SoCalGas, PG&E, and Edison have accepted the use of September 1989 Control forecast of 8.64% to calculate long-term debt for this this proceeding. SDG&E has used a higher estimate of 10% for AA utility bonds in 1990. We find insufficient support for an estimate as high as 10% given our finding that the overall interest rate climate is down for late 1989 and 1990. Since we have decided to retain use of the DRI Control forecast for determining equity returns for all of the reasons discussed earlier, we will continue its use for debt costs in this proceeding as well.

We are mindful of testimony in this proceeding that DRI plans to discontinue the AA utility bond forecast. In view of this, and the suggestions that alternative forecasts (or no forecasts) be used, we believe that parties in future cost of capital proceedings could benefit if a new methodology can be developed for incorporating interest rate trends (including spreads between A and AA bond yields) in the annual cost of capital determinations. We will direct our CACD staff to convene a workshop for the purpose of exploring such methodologies.

E. Business Risk

1. Background

Two benchmark United States Supreme Court decisions establishing the legal criteria for determining appropriate rates of return are Bluefield Water Works and Improvement Company v. West Virginia Public Service Commission, (1923), 262 US 679; 67 L ed 1176, 43 S. Ct. 675 and Federal Power Commission v Hope Natural Gas Company (1944) 320 US 591; L ed 333, 64 S. Ct. 281. In following

these criteria, we are concerned with, among other things, compensation to utility investors for the risks they assume. In D.84-12-068 (Application of Southern California Edison Company), we noted at page 31 that in estimating a utility's cost of capital for a future test period, we must identify the risks for which investors require compensation, evaluate the relative magnitude of these risks on the utility over the test period, and quantify these observations into an authorized rate of return on common equity and total capital.

Thus, a key task before us is to identify, evaluate, and quantify the risks, including business risks, facing the energy utilities in 1990. We believe the use of financial models can be of some help in this regard, because they reflect investors' assessments of the risks they face. However, we have previously noted that the application and interpretation of the models may not accurately reflect all of the intricacies of the financial market. (D.87-12-066, page 42.) It is therefore appropriate to combine qualitative assessments of risk with quantitative model results in arriving at a final judgement on required returns on equity.

Most of the utilities claim that business risk has increased since the last cost of capital review and should be recognized in setting their rates of return on equity. DRA, FEA, Los Angeles, and City of San Diego generally take the position that there has been little change in the overall level of business risks facing the energy utilities since the last cost of capital review, and that return on equity adjustments for business risk are not required for 1990. In this section we discuss business risk issues common to two or more of the utilities.

2. Elimination of the NRSA

In two major gas industry decisions (D.86-12-010 and D.87-12-039), the Commission has undertaken a major restructuring of the regulation of the gas distribution industry in California. An important component of this restructuring is the phased

elimination of balancing account treatment for noncore sales. The Supply Adjustment Mechanism (SAM) and the Gas Adjustment Clause (GAC) were eliminated May 1, 1988 for noncore gas customers, and replaced by the Negotiated Revenue Stability Account (NRSA) for a period of two years.

The scheduled elimination of the NRSA on April 30, 1990 is of particular concern, according to the gas utilities. The NRSA limits utility losses and gains in after-tax earnings to a range of 300 basis points above or below its authorized return on equity. SoCalGas notes that with its elimination, the exposure of earnings to sales fluctuations will be "essentially unlimited."

As an example of this exposure, the utilities point to PG&E's loss of $17.8 million for noncore sales in the eight months following the initial phase-out of SAM. Without the NRSA, the loss would have been $25.1 million. PG&E could lose $47 million on noncore sales in 1989. Although PG&E did not present percentage comparisons of these actual and potential losses with overall earnings, its witness did note on cross-examination that since the NRSA cap of 300 basis points was reached in 1988, and possibly will be reached in 1989, the conclusion could be drawn that PG&E's earnings on gas operations vary by 300 basis points. PG&E maintains that compared to the 300 basis point exposure range under the NRSA, a 25 basis point increase in its authorized return on equity is reasonable compensation for increased business risk. PG&E's testimony also notes that a September 1988 Drexel Burnham Lambert report on PG&E recognized the phased elimination of protective adjustment mechanisms as a "key issue" due to potential sales margin erosion.

DRA acknowledges that elimination of the NRSA will place gas utilities at greater risk for the noncore class, but believes the risk is an incremental one which is extremely difficult to quantify. At the same time, DRA believes that gas utilities will develop new strategies and benefit from current strategies such as

long-term contracts with up-front demand charges to mitigate the risks. DRA also notes that elimination of the NRSA provides opportunities for enhanced profits as well as risks. Finally, DRA states that the April 30, 1990 expiration of the NRSA could be extended if the Commission finds compelling reasons to do so.

City of San Diego argues that any loss of noncore customers for SDG&E would be minuscule in light of the small percentage of SDG&E's utility business represented by the portion of noncore sales subject to fluctuations.

We find that the elimination of the NRSA may result in an additional risk for the gas utilities that was not fully considered when their equity returns were last established. In last year's cost of capital proceeding we considered the NRSA as an offset to the additional risk posed by the elimination of the SAM. (D.88-12-094, page 20.) Since the NRSA will be eliminated after four months of the 1990 test period have passed, that offset to the SAM risk will not exist for the remaining eight months of the year. We note that at this time there is no reason to assume the NRSA will be extended beyond April 30 as DRA suggests.

In our judgement, the elimination of the NRSA should be considered as an additional risk in evaluating each gas utility's return on equity for 1990. However, we do not believe an increase of as much as 25 basis points above currently-authorized returns on equity as suggested by PG&E is necessary or reasonable, whether for gas utilities as SoCalGas and Southwest or for combination utilities such as PG&E and SDG&E. We recognize the NRSA protected PG&E from more than $7 million ($25.1 - $17.8 million) in after tax losses in the first eight months following implementation of the gas restructuring program, and may provide a greater savings in 1989, but when we evaluate risk, we are concerned with the range of future possibilities. Actual losses in the past tell us too little about the probabilities of future losses or gains that can be expected for PG&E and the other gas utilities.

In arriving at our judgement, we have also considered the likelihood that as gas utilities continue to operate in the new structure, they will begin to develop risk-reducing strategies as DRA suggests. We also recognize that investors have been aware of the phasing out of protective mechanisms, as indicated by the Drexel Burnham Lambert report on PG&E in September 1988. To the extent that investors' perceptions of the associated risks are reflected in the financial model analyses, the risks have already been quantified.

3. Other Gas Industry Restructuring Risks

In addition to the elimination of the NRSA, the gas utilities claim there are other "ongoing" risks associated with industry restructuring, including particularly changes resulting from federal regulatory policy. These include take-or-pay liability, the entry of federally-regulated pipelines in their service territories, and operating inefficiencies relating to the coordination of noncore customer-owned transportation gas. Other such risks claimed by the utilities include this Commission's ACAP proceedings in which the allocation of noncore revenues and costs is at issue.

DRA's witness believes these risks were primarily considered in previous cost of capital proceedings. (D.87-12-064, D.87-12-068, and D.88-12-094.) DRA also believes that the incremental risks facing the gas utilities are substantially mitigated through both the accommodating actions taken by the Commission and the utilities' positive efforts to meet the challenges of the evolving marketplace.

Los Angeles generally agrees with DRA, arguing that SoCalGas has exaggerated its business risks. Los Angeles believes that both the financial community and the Commission have already considered the business risks faced by SoCalGas as a result of industry restructuring, and that an increment to the return on equity to reflect such risks is neither required nor appropriate at

this time. City of San Diego also argues that SDG&E has not shown there are new risks which have not been previously considered.

This is not the first time we have evaluated the risks created by gas industry restructuring. In last year's energy utility cost of capital proceeding, we stated:

> "The investment community has been aware of risk associated with the new gas regulatory structure since 1986 and we have provided for that increased risk in Commission policy and in the attrition proceedings, most recently the 1988 attrition proceeding. (D.88-12-094, page 20.)

In that same decision, we found the following:

> "14. The new regulatory structure in the gas and electric industry has created new risk; however, such risk was recognized in the 1988 attrition proceeding.
>
> "15. The new regulatory structure has provided the energy utilities flexibility to meet both their needs and ratepayers' needs to respond to the competitive marketplace.
>
> "31. Increased risk associated with regulatory changes in the electric and gas industry were considered in the 1988 attrition year proceeding.
>
> "33. The investment community has been aware of increased risk associated with the new gas regulatory structure since 1986.
>
> "45. The intent of decisions related to the gas and electric industry restructure is to provide the regulated utilities a means of responding to marketplace changes, keyed to competition and bypass. (D.88-12-094, Findings of Fact, pages 42, 44 and 45.)

We have carefully considered the evidence and arguments in light of our previous findings, and conclude that while restructuring of the gas industry due to federal and state policies has created new risks in the past few years, such risks have

previously been considered by this Commission and incorporated in our rate of return deliberations. For the gas utilities as a group, we find no justification for enhancing returns on equity in 1990 as a result of the restructuring, except as discussed above with respect to the NRSA.

4. Electric Industry Competitive Risks

The arguments that new risks are facing electric utilities as a result of third party generation and self-generation are no more persuasive than those made for gas industry restructuring. Edison and PG&E provided testimony that third-party capacity and sales have grown rapidly, with as much as a 90% increase in the proportion of power supplied by third party producers from 1987 to 1988 in the case of Edison. Edison expects Qualifying Facilities (QF) power producers to bring another 1,300 MW on line in 1989 and 1990, a 50% increase over year-end 1988. PG&E purchased 9,300 Gwh, or 14% of total 1988 sales from QF producers. Edison and PG&E have not, however, persuaded us that the risks associated with this growth are significantly different from those previously considered in their cost of capital reviews. Substantial growth in the number of third party contracts and in the capacity they provide does not, alone, indicate new risk for 1990 which was unforeseen a year ago.

DRA believes, and we agree, that third-party production risks and bypass risks are real and should be considered in determining returns on equity. Undoubtedly there is less certainty in resource planning, but as DRA points out, these risks have already been recognized in past rate of return proceedings. (D.88-12-094, Findings of Fact 14 and 17, page 42.) Also, we note that while third-party generation creates resource planning risks, there are benefits in the reduction of the utility's exposure to large baseload plant risks.

At the same time, as noted by City of San Diego, we recently decided to retain the ERAM (Electric Revenue Adjustment

Mechanism) and ARA (Attrition Rate Adjustment) protection mechanisms (D.89-05-067, May 26, 1989). Elimination of these mechanisms had been considered since late 1986, creating an additional risk which was addressed in last year's cost of capital proceeding. (D.88-12-094, Finding of Fact 24, page 43.) Retention of these mechanisms may represent a reduction of risk for electric utilities compared to one year ago, although we do not consider this a substantial reduction.

We also agree with DRA that bypass risk is mitigated by our policy of moving closer to EPMC (equal percentage of marginal cost), and the Commission's authorization of special contracts for large customers to encourage their remaining on the system. Further, DRA notes that diminished concern over bypass risk was a factor in our deciding to retain the ERAM mechanism.

F. Updates

Several parties have urged that we consider the interest rate environment prevailing at the time we reach a decision in this proceeding and the impact it has on both equity returns and long-term debt costs. The general theme of their concern is that economic conditions prevailing at the time of the hearings are likely to change by the end of the year, and rates of return for 1990 should reflect the most recent possible information.

We are sympathetic to these concerns, but we are largely constrained from implementing the various proposals because of practical considerations involving our decision process. Under the provisions of § 311(d) of the Public Utilities (PU) Code, the Commission cannot consider a matter until at least 30 days after the proposed decision of the ALJ is filed, except in an unforeseen emergency situation or upon the stipulation of all the parties to the proceeding. Unavoidably, there will normally be several weeks of delay between the closing of the record and the date of a decision.

Additionally, it seems unlikely that reopening the record to receive additional interest rate information would be as simple a matter as the parties apparently anticipate. Given the extent of disagreement and complexity of the issues noted in our discussion of interest rates in this opinion, we are somewhat doubtful that parties would easily reach agreement as to what the "interest rate environment" is.

As we noted at the outset of this opinion, we just recently considered and adopted procedures for ACC proceedings, including update procedures, in the rulemaking that resulted in our decision (D.89-01-040). The adopted update procedure was followed in this proceeding with the submittal of late-filed Exhibit 40, which included September interest rate forecasts. Under normal circumstances, we intend to follow the procedures adopted in the Rate Case Plan decision for updates in ACC proceedings.

G. Optimal Capital Structure

1. Background

In last year's energy utility cost of capital proceeding we determined that the concept of an optimal capital structure (OCS) for California utilities should be considered in this proceeding. We directed SoCalGas, PG&E, Edison, SDG&E, and SPPC to "address the optimum balanced capital structure in their respective electric and gas regulated industry in their next financial attrition proceeding." (D.88-12-094 and D.89-04-051.)

Our decision to address the capital structure issue was an outgrowth of our determination that SDG&E's proposed capital structure in that proceeding was out of line with that of the other energy utilities and that a lower equity ratio should be adopted for SDG&E. The overriding concern in doing so was to ensure that equity ratios we adopt in determining overall rates of return on rate base are no greater than required to maintain reasonable credit ratings and the ability to attract capital.

As directed, the utilities included comments on the OCS issue in the testimony of their cost of capital witnesses. DRA witnesses Phyllis White and Clayton Tang and FEA witness Philip Winter presented testimony and recommendations as well. The material issues are whether we should adopt target or guideline capital structures for energy utilities, and if we do, how the targets should be determined, whether there should be a specified range of permissible capital ratios, whether target capital structures should be the same for all utilities, how such targets should be implemented, and whether they should be periodically reviewed and adjusted.

There is general agreement on certain financial principles underlying the OCS concept. Equity financing is more costly than debt financing because of its higher risk. Because debt financing is less costly and it is tax-deductible, ratepayers benefit from the use of debt financing, or leverage, but there are limits to this benefit. As debt ratios are increased and equity ratios are correspondingly lowered, credit ratings are downgraded and financial risk for equity investors increases, requiring greater returns on equity.

Additional leverage is therefore advantageous to ratepayers up to the point that overall capital costs begin to increase as a result of increased cost of equity caused by greater financial risk and increased cost of debt due to degradation of credit ratings. Determining the appropriate levels of debt and equity is complicated and made more so because firms also use preferred stock to raise capital. Preferred stock has qualities of both debt and equity financing and its cost is between that of debt and equity. The OCS is the particular combination of debt, preferred stock, and equity which produces the lowest overall cost of capital, with consideration given to the need to maintain a degree of financial flexibility.

2. Comments and Proposals of the Utilities

The comments of the utilities are generally summarized as follows:

1. Determining the OCS for a firm requires a great deal of judgement; the OCS cannot be precisely determined through quantitative means. Despite extensive study of the OCS issue by financial and academic experts, no consensus on specific structures has emerged. Therefore, if OCS targets are established, there should be reasonable ranges within which utilities exercise managerial discretion.

2. Any OCS targets adopted should be designed to maintain investment grade bond ratings. Edison and SDG&E recommend the bond ratings of single A and higher be used. However, there is a weakness in quantitative approaches to determining target capital ratios on the basis of bond rating criteria because other factors besides debt ratios affect ratings, and ratings are not necessarily changed with changes in financial ratios.

3. An adopted OCS must be based on consideration of the need for utilities to maintain the flexibility to raise new financing at all times.

4. A generic OCS does not exist for all California energy utilities. Differences in risks, embedded debt costs and preferred stock costs, and financing techniques among firms will result in a different OCS for each firm.

5. A utility's OCS will vary over time for the same reasons that the OCS varies among firms. Any adopted target will require periodic review and adjustment. Other reasons for periodic review include variations in the spread between debt and equity costs and possible changes in bond rating criteria.

6. Any adopted OCS targets should be based on consideration of financial capital structures, which reflect short-term debt and capital leases as well as the long-term debt considered in ratemaking capital structures. Bond ratings

> agencies consider total debt leverage, not just long-term debt. Setting a target debt ratio to achieve a given bond rating would not result in achievement of that rating if only long-term debt is included. The financing of assets which are excluded from rate base (such as fuel oil inventories, which are financed by permanent short-term debt) has the same impact on a utility's risk as long-term debt financing of rate base assets.

Among the utilities, only SDG&E proposed specific capital structure guidelines. SDG&E believes that although optimal bond ratings will not remain static over time, the optimal bond rating for each utility will likely fall within the A to AA rating categories. Standard & Poor's guidelines for electric and combination utility debt include debt ratios of 39% to 46% for an AA rating and 44% to 52% for an A rating. Using the midpoint of these rating guidelines and the 7% average preferred stock ratio for electric utilities, SDG&E determined that the following capital structure guidelines are reasonable:

Long-term debt:	45.5% ± 5%
Preferred Stock:	7.0% ± 2%
Common equity:	46.0% ± 5%

3. DRA's Proposal

DRA acknowledges that energy utilities are facing increasingly competitive markets and will therefore have some incentive to minimize costs, including capital costs. However, DRA believes that such incentives may not be adequate to ensure that utilities make efficient use of leverage. As DRA's witness White testified, many utilities remain primarily monopolistic in character. DRA believes that the Commission's practice of authorizing very similar returns on equity to utilities within a particular industry has led California utilities to hold more common equity financing than have comparable risk-positioned utilities. White noted that while corporate leverage of

nonregulated firms has increased since 1981, the opposite has been true of energy utilities. In order to balance the interests of shareholders and ratepayers, DRA maintains there should be regulatory oversight of capital structures.

DRA maintains that the OCS for regulated firms can be determined on the basis of finance theory, empirical analysis, and informed judgement. DRA compared California energy utilities with comparable groups of energy utilities and found that the California energy utilities hold higher proportions of equity and tend to outperform comparable utilities in areas of interest to investors. DRA concludes, however, that the differences are not significant.

DRA also developed a linear programming model (LPM) which calculates the OCS given the bond rating of a utility. DRA defined the OCS as the capital structure that results in the lowest pre-tax weighted average cost of capital while maintaining Standard and Poor's quantitative bond rating criteria for a specific bond rating. DRA used the model to determine the OCS for electric utilities with BBB, A, and AA bond ratings, and separately for gas utilities with the same bond ratings.

As a result of its analysis, DRA recommends that California utilities be given prospective direction to manage their financial capitalization toward the OCS targets shown below, which are based on criteria for single-A bond ratings. City of San Diego supports DRA's recommendations, and SoCalGas supports the targets for gas utilities provided they are reviewed annually.

	Electric	Gas
Long-term debt:	48%	43%
Preferred Stock:	10	10%
Common equity:	42	47%

DRA also recommends that the Commission recognize that:

"1. Utilities should manage their financial capital structures according to S&P single A financial benchmarks and their financial

capital structure should form the basis for their ratemaking capital structure.

"2. Utilities should be given prospective direction to manage their financial capitalization towards the OCS.

"3. Demonstrative progress towards the OCS must be evident within three years, after which utilities bear the burden to prove that the excessive capital costs, associated with their chosen financing, should not be disallowed.

"4. Issuing preferred stock is an acceptable financing alternative that yields savings to ratepayers. Utilities should maximize - not reduce - preferred stock financing in their investment portfolios.

"5. In the interest of protecting utility credit quality, utilities that have diversified and/or have adopted alternative corporate structures should be directed to show, as part of their next cost of capital proceeding, how utility operations are insulated from the operations of diversified enterprises.

"6. Finally, all else being equal, lower returns should be authorized for utilities that hold higher than average common equity ratios, and vice-versa.

DRA views its OCS targets as efficiency or performance indicators which could serve as a "red flag" for indicating possible management impropriety in capital financing. For electric and gas utilities, common equity ratios exceeding 42% and 47%, respectively, in three years would be unacceptable without a compelling reason put forth by the utility.

DRA explains that its recommendation to maximize preferred stock financing encompasses creative financing techniques such as seasonal financing under the category of preferred stock.

4. FEA's Proposal

FEA's witness Winter agrees with DRA that utilities may attempt to maximize returns to shareholders through choice of a suboptimal capital structure. FEA believes it is appropriate for regulators to scrutinize a utility's capital structure choices just as it is other operating decisions.

FEA also agrees with DRA that capital structures which support bond ratings stronger than single A are not cost efficient and should not be used for ratemaking. Winter presented an analysis showing that the spreads between yields on A rated electric utility bonds and higher rated bonds are currently so small that the reductions in debt required to achieve the higher ratings are not justified. Winter concluded that for electric utilities, ratings higher than single A are justified less than 15% of the time and have not been justified since the early 1980's. A further indication that single A ratings are adequate and appropriate is the fact that 46% of investment grade industrial firms have an A rating, whereas only 4.9% of such firms have AAA ratings and only 16.2% have AA ratings.

FEA recommends that for predominantly electric utilities, the Commission adopt capital structures that contain 44% to 52% debt, 5% to 10% preferred stock, and the remainder common equity. FEA notes that the greatest cost savings are associated with debt and preferred stock ratios near the upper ends of these ranges.

5. Discussion

We recognize that capital structures which maximize shareholder interests may not always result in the maximum benefit to ratepayers, and, therefore, that regulatory oversight is required to assure an appropriate balancing of interests. The question before us is how such oversight should be achieved now and in the future. Our decision in last year's cost of capital proceeding to limit SDG&E's authorized ratemaking equity ratio is an example of our prior approach. We conclude that we should

continue to evaluate capital structures on a case by case basis in proceedings such as this. We will not adopt fixed target financial or ratemaking capital structures. However, we recognize that the analytical methods presented in this proceeding, particularly those offered by DRA, will be valuable in our evaluations.

It is clear that determining whether any utility's capital structure will result in the lowest overall cost of capital over the long term involves considerable judgement. It strikes us that the regulatory task of determining the appropriate capital structure for a utility is not unlike the task of determining the appropriate return on common equity. In both cases it is necessary to make use of quantitative analyses which are tempered by judgement which is based on consideration of financial market conditions and the particular circumstances of a utility.

Despite evidence from DRA's LPM analysis that the OCS is not sensitive to various cost of capital scenarios, we are concerned that the recommended targets imply too much precision and accuracy, and make insufficient allowance for the possibility that the OCS will change over time and vary among utilities. DRA's testimony does show that decreases in equity costs towards the cost of debt and preferred stock could cause the model to select other capital structures. Also, bond ratings criteria are sometimes changed, the spread between yields on bonds of different ratings varies, and risk premiums of equity returns over debt yields vary.

Creating a presumption that one particular capital structure will be optimal over a long term leaves too little room for the possibility that other structures may be reasonable for any variety of reasons. Although DRA's approach would allow utilities to prove their chosen structure is reasonable despite being different from the fixed target, we are concerned that utilities might tend, in an abundance of caution, to manage their capitalization towards the targets even if it were not in the ratepayers' or shareholders' interests to do so.

While oversight of utility capitalization is necessary and appropriate, we believe utilities must be given some discretion to manage their capitalization with a view towards not only shareholder interests but also regulatory requirements and ratepayers' interests. Establishing ranges around the fixed targets might appear to allow such managerial discretion, but we believe that such an approach could aggravate the problem by creating the presumption that any capital structure consistent with the allowable ranges is reasonable when that might not be the case. We conclude that regulation to ensure that utilities are managing their capitalization to optimal levels will be most effective if it is on a case-by-case basis and if it allows for consideration of variations over time and among utilities.

It should be emphasized that we are not excusing utilities from their burden of showing that their capital structures and their ratemaking capital structure proposals are reasonable and justified in cost of capital proceedings. We anticipate that capital structure issues will continue to be important parts of these proceedings, particularly the question whether equity-rich structures should be adopted.

DRA's recommendation that issuance of preferred stock be considered an acceptable financing alternative has merit. Although we are not adopting DRA's target recommendation of 10% preferred stock, we will give careful consideration to the utilities' use of preferred stock and make adjustments to authorized capital structures if they are not making appropriate use of this financing alternative.

We believe that DRA's recommendation that utilities that have diversified and/or adopted alternative corporate structures be directed to show, in the next cost of capital proceeding, how utility operations are insulated from the effects of their other enterprises has merit. The proposal will be adopted.

IV. Southern California Gas Company

A. Background

By its application, SoCalGas requests an authorized return on equity of 14.0% and an overall rate of return of 11.50% for 1990. It estimates that the related revenue requirement increase is $23.565 million annually. This increase incorporates the revenue requirement increase requested in SoCalGas' pending test year 1990 general rate case application (A.88-12-047). Because the application is based in part on the April 1989 DRI forecast for AA utility bonds, SoCalGas requests that the authorized cost of capital and revenue requirement incorporate the latest available DRI forecast at the time a decision is reached in this proceeding.

SoCalGas' presently authorized and requested rate of return, as well as DRA's and Los Angeles' recommendations, are depicted in the following tables:

SoCalGas' Present Authorization
(D.88-12-094)

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	45.50%	9.66%	4.40%
Preferred Stock	9.30	7.32	0.68
Common Equity	45.20	13.00	5.88
TOTAL	100.00%		10.96%

SoCalGas' Request*

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	45.00%	9.27%	4.17%
Preferred Stock	9.70	7.36	0.71
Common Equity	45.30	14.00	6.34
TOTAL	100.00%		11.22%

* Updated to reflect the September 1989 DRI forecast.

DRA's Recommendation*

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	45.00%	9.22%	4.15%
Preferred Stock	9.70	7.31	0.71
Common Equity	45.30	12.25	5.55
TOTAL	100.00%		10.41%

* Updated to reflect the September 1989 DRI forecast.

Los Angeles' Recommendation

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	45.00 %	9.468%	4.261%
Preferred Stock	9.70	7.400	0.718
Common Equity	45.30	12.650	5.730
TOTAL	100.00%		10.709%

SoCalGas presented the testimony of its Vice President and Controller, Ralph Todaro (Todaro). DRA, Los Angeles, and FEA

presented the testimony of Edwin Quan (Quan), Manuel Kroman (Kroman), and John B. Legler (Legler), respectively. Legler's testimony addressed return on equity issues.

B. Capital Structure

SoCalGas proposes a capital structure which includes an increase in the equity ratio from the currently authorized 45.2% to 45.3% for 1990. DRA finds that the proposal is not significantly different from that used to set the utility's rate of return for 1989, and concludes that it is both reasonable and within the range of optimal as defined in DRA's optimal capital structure study. Therefore we will adopt the proposed 1990 capital structure consisting of 45.00% long-term debt, 9.70% preferred stock, and 45.30% common equity.

C. Cost of Long-Term Debt and Preferred Stock

As shown in late-filed Exhibit 40, which incorporates DRI's September, 1990 Control interest forecast for AA rated utility bonds, SoCalGas' updated estimate of its embedded long-term debt cost for 1990 is 9.27%. The difference between this estimate and DRA's lower estimate of 9.22% is due to the different risk premiums used to reflect SoCalGas' lower bond rating. Although Los Angeles' cost of capital recommendation for SoCalGas includes a long-term debt component, Los Angeles also agreed that the adopted cost should reflect updated forecast information. Accordingly, since we have adopted DRA's recommendation for a 25 basis point additive, we adopt its 9.22% estimate of long-term debt cost for 1990.

There also is a five basis point difference between SoCalGas' and DRA's estimates of preferred stock costs due to the different risk premium additives used. The parties did agree that the estimated cost of the planned issue for 1989 should be 61 basis points less than the estimate used for A rated utility bond issues.

For the same reason we adopt DRA's long-term debt cost, we will adopt its 7.31% cost for preferred stock for 1990.

D. Return on Common Equity

The principal issue concerning SoCalGas' application is the appropriate return on common equity for SoCalGas in 1990. The following table summarizes the position of each party:

Party	Recommended Return
SoCalGas*	14.00%
DRA: Recommended range	11.90% - 12.40%
DRA: Specific Recommendation	12.25
Los Angeles	12.65 (Maximum)
FEA: Recommended range	12.00% - 12.50%
FEA: Specific Recommendation	12.25

* SoCalGas acknowledged that based on current interest rate information as of the time of the hearings, a return on equity of 13.25% could be appropriate.

SoCalGas, DRA, and FEA submitted testimony on the results of various financial models which they considered in developing their return on common equity recommendations. SoCalGas and DRA used the Discounted Cash Flow Analysis (DCF), Risk Premium Analysis (RPM), and Capital Asset Pricing Model (CAPM) as part of their analyses. FEA used the DCF and RPM models. Los Angeles' witness Kroman did not use these models in arriving at his recommended return on equity, but did extensively analyze SoCalGas' use of the models.

Detailed descriptions of each financial model are contained in the record and are not repeated here. In previous cost of capital proceedings we have found that parties using the financial models invariably caution against too much reliance on them, and urge that the model results be tempered by judgement. This proceeding yielded no exception to that general rule. Los Angeles' witness Kroman took a harsher view, indicating that in his view the models are of virtually no value in determining a utility's return on equity. Kroman did acknowledge that they may

be of some value in discerning trends about investors' expectations and required returns if consistent data and assumptions are used over time. Other parties believe that the models, if properly applied, can be useful to establish a range of returns within which judgements about the precise return can be made.

We believe that despite these well-recognized limitations on the value of the three financial models, they are nevertheless useful in establishing a range of required returns to consider in selecting the authorized return. They may also be useful in evaluating trends of investor expectations when consistent assumptions and data sets are used in the analysis. However, in the final analysis, it is the application of our judgement that is crucial in determining the appropriate return on equity, not the accuracy of a particular model.

The following table summarizes the model results presented by witnesses Todaro, Quan, and Legler:

Model	Party	Range
DCF	SoCalGas (Group of 8)	12.09% - 15.45%
	DRA (Group of 14)*	12.05 - 12.58
	DRA (Company-specific)*	10.44 - 10.98
	FEA (Group of 24)*	11.5 - 12.0
	FEA (Company-specific)*	11.7 - 13.1
RPM	SoCalGas (Group of 8)	12.74 - 14.98
	DRA (Group of 14)	11.38 - 12.85
	FEA (Long-term premiums)	13.1 - 13.3
	FEA (5 year premiums)	12.0 - 12.1
CAPM	SoCalGas (Group of 8)	13.47%
	DRA (Group of 14)*	12.51 - 12.56
	DRA (Company-specific)*	13.31 - 13.43

* Although DRA presented the company-specific results of the DCF and CAPM models for Pacific Enterprises, SoCalGas' parent company, DRA recommends that the estimate of the appropriate return on common equity be based on the comparable group of 14 gas utilities. Similarly, FEA believes it is more relevant to review DCF results for comparable companies.

SoCalGas used both historical dividend yields and Value Line Dividend forecasts to estimate the growth component of its DCF model. The historical yields resulted in a range of 14.98% to 15.45% required return on equity. The forecasted growth version of the DCF model resulted in an estimate of 12.09%. SoCalGas believes that the upper range of DRA's DCF results would have been as much as 200 basis points higher if it had used historical data. In the company's view, historical data should be considered as well as forecasts because it is less subjective.

DRA believes historical dividends and earnings growth may not provide a good indication of future dividend growth, and gave little weight to them. In DRA's opinion, forecasted and sustainable growth indicate that present market conditions cannot reasonably support the historical rate of dividend growth. We recognize that there may be an element of circularity in the historical growth version of the DCF model in that high historical levels of growth could alone incorrectly indicate a future need for high returns. Nevertheless, we conclude that some weight can be given to historical growth rates in our overall assessment when other measures of growth are also considered.

FEA believes that Todaro's DCF analysis is flawed because the eight comparable gas utilities had widely varying DCF results, ranging form 11.0% to 21.3%. FEA believes this indicates the utilities used by SoCalGas do not have comparable risks. According to FEA, an indicated required return of 21.3% renders the group analysis meaningless. Los Angeles also believes the group comparison is unrealistic because SoCalGas is much larger and therefore less risky than the utilities it was compared to.

While we expect to find a range of estimates in looking at comparable utilities, we believe an analysis that includes required returns as high as 21.3% must be given diminished weight, particularly since that observation is included in a relatively small sample of eight comparable utilities.

As part of its RPM analysis, SoCalGas used the April 1989 DRI Control forecast and a 50 basis point additive to estimate yields on utility bonds of A rated utilities. FEA notes that the results of SoCalGas' RPM analysis would be significantly lower had the July DRI forecast been used. SoCalGas acknowledges that using the September DRI forecast yields a lower RPM estimate than the April forecast, stating that based on the five-year average risk premium over utility bonds, the required return would be 13.58% instead of 14.98%. We agree with FEA, and note further that SoCalGas' estimate of A rated bond yields for 1990 is based on a spread of 50 basis points over the forecasted AA rate. For the reasons stated earlier in our discussion of the spread between A and AA bonds, this could result in the model result being overstated.

As with SoCalGas' DCF analysis, FEA believes that the risk premium for one of the utilities in the comparable group, Atlanta Gas light, is unrealistic because it indicates an expected return on equity of about 19%. We agree, and conclude that the upper limit of its RPM range is probably overstated.

FEA criticizes SoCalGas' CAPM analysis because of its use of adjusted Value Line betas and because it relies on outdated interest rate forecasts. FEA believes a simple updating of the CAPM analysis would result in a required return below 13.0% compared to the 13.47% estimate in its testimony.

Los Angeles presented an analysis comparing SoCalGas' use of the financial models in this proceeding with its analysis in last year's proceeding. Kroman's testimony showed that if SoCalGas had used the same group of comparable companies in both years, the model analysis would have demonstrated significantly lower equity returns are required this year. Kroman concludes that instead of an increase in SoCalGas' return from the currently authorized 13.0% to 14.0%, a decrease in the range of 75 to 80 basis points is

warranted on the basis of consistent application of the financial models.

In arriving at his recommended return on equity, Kroman used a comparative earnings approach. His analysis shows that returns on equity for utilities with bond ratings similar to SoCalGas typically fall within the range of 12% to 13%. Using this approach with Value Line estimates, he found that a composite return for the gas industry is falling from 13.0% in 1989 to 12.5% in 1990. Kroman believes that returns in this range are adequate to support investment grade bond ratings, and meet interest coverage tests.

SoCalGas states that its requested return on equity will result in an interest coverage ratio of 3.40 in 1990. A 12.25% return on equity as recommended by DRA and FEA will result in a coverage ratio of 3.19. SoCalGas believes that ratio is barely adequate under Standard and Poors' guideline of 3 to 4.25 times annual interest expense and other fixed charges in order to maintain an A bond rating. Los Angeles notes that bond rating agencies consider other factors besides interest coverage guidelines when rating bonds.

SoCalGas states that its financial risk is relatively high due to its relatively low proposed equity ratio of 45.3%. Since the proposed capital structure is not significantly different from the currently adopted structure, DRA believes, and we concur, that the level of financial risk facing SoCalGas has not changed significantly since 1989. We do note that the common equity ratio we are adopting is 10 basis points higher than the currently-authorized ratio.

SoCalGas argues that it faces an additional business risk due to the proposed merger of SDG&E with Edison. According to SoCalGas, the combined entity will be its largest customer. SoCalGas claims that concentrating so much throughput in one customer significantly raises the risk that authorized rates of

return will not be achieved. We find nothing in this record to show the extent, if any, to which SoCalGas' 1990 earnings may be threatened by the proposed merger. We conclude that an adjustment to the authorized return on equity is not required as a result of the proposal.

After considering all the evidence of the market conditions, trends, and the quantitative models presented by the parties, we conclude that a 13.00% return on common equity is just and reasonable for SoCalGas in 1990. This return gives recognition to the elimination of NRSA and the overall level of business risk facing SoCalGas and the gas industry. We are also recognizing that the overall levels of inflation and interest rates appear to be more favorable than when we established SoCalGas' return for 1989 one year ago, but at the same time there is some uncertainty and volatility in financial markets. Additionally, we believe this return on equity is more reflective of the range of returns indicated by the parties' financial model results than the 12.25% return recommended by DRA and FEA, and in particular gives some weight to the historical growth rate method for the growth component of the DCF model. We believe our adopted return is sufficient to allow SoCalGas to maintain adequate interest coverage.

E. Adopted Cost of Capital

The 13.00% adopted return on common equity produces an overall rate of return of 10.75% for 1990, as shown in the following table depicting the adopted cost of capital:

SoCalGas' Adopted Cost of Capital

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	45.00%	9.22%	4.15%
Preferred Stock	9.70	7.31	0.71
Common Equity	45.30	13.00	5.89
TOTAL	100.00%		10.75%

F. Implementation

The proposed rates accompanying SoCalGas' application reflect the cost allocation guidelines proposed by the utility in its 1989 Annual Cost Allocation Proceeding (ACAP) application (A.89-04-021). SoCalGas points out that under our modified Rate Case Plan, gas rate design and revenue allocation issues are addressed in ACAPs, not in general rate cases or cost of capital filings.

SoCalGas requests that in the event we issue an ACAP decision prior to reaching a decision in this proceeding, the order in this proceeding provide for incorporation of the guidelines adopted by that ACAP decision in its advice letter filing. If we decide this matter before the ACAP, SoCalGas requests the order in this proceeding allow SoCalGas to use then-existing cost allocation guidelines in its advice letter filing. To accommodate either possibility, we will provide that SoCalGas shall incorporate the most-recently adopted cost allocation guidelines.

V. Pacific Gas and Electric Company

A. Background

PG&E filed its current general rate case application (A.88-12-005) prior to our adoption of a final order modifying the Rate Case Plan and establishing an annual cost of capital (ACC) proceeding. However, in anticipation of our establishing an ACC proceeding, PG&E did not propose a cost of capital change in its general rate case application.

At the time it filed its ACC application, PG&E requested a return on equity of 13.75% and a rate of return on rate base of 11.38%. The revenue requirement increase based on an 11.38% rate of return was estimated to be $41.835 million, or 0.65%, for the electric department, and $11.937 million, or 0.76%, for the gas department. Prior to the hearings, PG&E distributed revised

testimony in which it lowered its requested return on equity from 13.75% to 13.25%. The application states that in accordance with the Diablo Canyon Settlement Agreement adopted in D.88-12-083, PG&E's analysis supporting its request excludes any consideration of the impact of the settlement on the required rate of return.

PG&E's presently authorized and requested rate of return, and DRA's recommendations, are depicted in the following tables:

PG&E's Present Authorization
(D.88-12-094)

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	46.25%	9.39%	4.34%
Preferred Stock	7.00	8.79	0.62
Common Equity	46.75	13.00	6.08
TOTAL	100.00%		11.04%

PG&E's Request*

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	47.00%	9.33%	4.39%
Preferred Stock	6.25	8.79	0.55
Common Equity	46.75	13.25	6.19
TOTAL	100.00%		11.13%

* Updated to reflect the September 1989 DRI forecast.

DRA's Recommendation*

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	47.00%	9.32%	4.38%
Preferred Stock	6.25	8.79	0.55
Common Equity	46.75	12.15	5.68
TOTAL	100.00%		10.61%

* Updated to reflect the September 1989 DRI forecast.

PG&E presented the testimony of Jack F. Jenkins-Stark and Laura A. Gilmore. DRA presented the testimony of Edwin Quan, and FEA's witness Legler addressed the utility's cost of equity.

B. Capital Structure

PG&E's proposed capital structure includes a 75 basis point increase in its long-term debt ratio and a corresponding reduction in its preferred stock ratio compared to the currently adopted authorization. There is no change in the proposed equity ratio. DRA concludes that the proposal, which it concludes is not significantly different from that used to set the utility's rate of return for 1989, is reasonable and within the range of optimal as defined in DRA's optimal capital structure study. The long-term debt and preferred stock ratios are within the ranges of 44% to 52% and 5% to 10%, respectively, recommended by FEA for electric utilities. We will adopt the proposed 1990 capital structure consisting of 47.00% long-term debt, 6.25% preferred stock, and 46.75% common equity.

C. Cost of Long-Term Debt and Preferred Stock

As shown in late-filed Exhibit 40, which incorporates DRI's September, 1990 Control interest forecast for AA rated utility bonds, there is a minor difference of one basis point between PG&E's updated 9.33% estimate of embedded long-term debt cost and DRA's estimate of 9.32%. The difference is largely due to the higher risk premium used by PG&E to reflect its single A bond rating. A small amount of the difference is attributable to PG&E's use of the average of the third and fourth quarter 1989 DRI forecasts for remaining 1989 debt issuance compared to DRA's use of only the fourth quarter 1989 forecast. Since we have adopted DRA's recommendation for a 25 basis point additive, and DRA's use of the fourth quarter forecast is consistent with D.85-12-076, we will adopt its 9.32% estimate of long-term debt cost for 1990.

PG&E's 8.79% cost of preferred stock, which is not disputed, should be adopted for the 1990 test year.

D. Return on Common Equity

The major issue in deciding PG&E's cost of capital is the appropriate return on common equity for PG&E for 1990. The following table summarizes the position of each party:

Party	Recommended Return
PG&E	13.25%
DRA: Recommended range	11.90% - 12.40%
DRA: Specific recommendation	12.15
FEA: Recommended range	12.00% - 12.50%
FEA: Specific recommendation	12.25

PG&E, DRA, and FEA submitted testimony on the results of various financial models which they used as a starting point in arriving at their return on common equity recommendations.

The following table summarizes the model results presented by witnesses Gilmore, Quan, and Legler:

Model	Party	Range
DCF	PG&E (Group of 16)	12.45%
	DRA (Group of 21)	11.78 - 12.32
	FEA (Group of 23)	10.9 - 11.3
	FEA (Company-specific)	10.9 - 12.4
RPM	PG&E (Group of 16)	11.85 - 13.78
	DRA (Group of 21)	11.76 - 12.43
	FEA (Long-term premiums)	13.3 - 13.4
	FEA (5 year premiums)	13.1
CAPM	PG&E (Group of 16)	12.59 - 14.43
	DRA (Group of 21)	12.67 - 12.70

PG&E and DRA used only comparable group data in their financial model analyses. DRA notes that this is consistent with the Diablo Canyon Settlement Agreement, which precludes recognizing the impact of the settlement on future determinations of the utility's rate of return. DRA believes that it is nearly impossible to isolate the impact from investors' evaluations of PG&E's common stock.

FEA believes there is a flaw in PG&E's DCF methodology due to a mismatch in the time periods used to compute the estimated dividend yields for 1990. The dividend estimate was based on the 1988 dividend being compounded for two years. The price was based on second quarter 1989 data. FEA believes the price will be understated with this method, and that the dividend yield component of the model will be overstated as a result. We note that despite the mismatch, the dividend yields computed by PG&E for the group of 16 utilities compares favorably with the range of dividend yields computed by DRA and FEA. The range for PG&E's group is 6.29% to 8.82%, and the average is 7.57%. (Exhibit 22, Table 2-7.) The range of group average yields shown in DRA's calculations is 7.23% to 7.63%, and the yield selected by DRA for use in its model is 7.48%. (Exhibit 34, Tables 9 and 11.) The group average dividend yields shown in FEA's calculations range from 7.45% to 7.89%. (Exhibit 24, Schedule 14.) We conclude that the mismatch noted by FEA does not result in a substantial error in the final model results.

For its RPM and CAPM analysis, PG&E used DRI's Control and Late-Recession Forecasts to estimate 30-year Treasury bond rates and AA utility bond rates. PG&E used a 50 basis point spread to estimate the yields on A-rated utility bonds.

DRA argues that PG&E's RPM and CAPM model results are overstated because the utility misused the DRI interest rate forecasts. According to DRA, PG&E's RPM range would have been 11.04% to 13.78% instead of the 11.85% to 13.78% range it presented. Similarly, PG&E's CAPM results would have been 40 basis points lower. DRA explains that DRI produces two other forecasts not used by PG&E, and both of these forecast lower rates. The Late-Recession forecast produces the most negative view of interest rates. FEA agrees with DRA that PG&E misused the DRI Forecasts.

We agree with DRA that either the Control forecast only should be used or all four should be used. Although the Control

and Late-Recession forecasts have the highest combined probability assigned by DRI, we find it is unreasonable to completely ignore the two more optimistic forecasts.

FEA objects to the method used by PG&E to calculate the risk premium component of the RPM model. The use of historical dividends growth resulted in excessive premiums, according to FEA. We addressed problems with using historical growth in reviewing the parties' DCF model analysis for SoCalGas, and concluded that some consideration can be given to historical growth rates if other measures are used as well.

In addition to using the three financial models, PG&E made several comparisons using current market information to show that its request is reasonable. In PG&E's view, its requested return on equity of 13.25% is reasonable in comparison with the earnings that Value Line projects for comparable utilities. PG&E points further to the 12.99% average of returns earned by comparable utilities in the twelve months ending with the second quarter of 1989 as demonstrating the reasonableness of its request. Finally, PG&E notes that a survey of authorized returns in the electric utility industry demonstrated that such utilities were authorized, on average, a 13.22% return on equity in the second quarter of 1989.

We find problems with each of PG&E's comparative analyses and give little weight to them in our deliberations. First, as DRA and FEA noted, the Value Line earnings projections include periods past 1990, the period we are concerned with for this proceeding. Also, unlike the three financial models, which are intended to reflect investors' perceptions of risk and their return requirements, a projection of what earned returns will be may not perform that function. As FEA observes, the Value Line forecasts used by PG&E are projected book returns, which could overstate the market returns required by investors. Likewise, a showing that earned returns in the four quarters ending with the second quarter

of 1989 averaged 12.99% does not indicate what investors require for 1990. Finally, an average of authorized returns for the electric industry in the second quarter of 1989 is of little value in determining a required return for PG&E, when there is no assurance that the jurisdictions involved use the same criteria as this Commission in authorizing returns on equity, that they are reasonably current, or that they are reflective of comparable utilities.

PG&E argues that it will experience a higher level of financial risk in 1990 due to the 75 basis point reduction in its percentage of preferred stock and corresponding increase in long-term debt. We agree with DRA that PG&E's capital structure is not significantly different from the currently adopted structure, and conclude that the level of financial risk facing PG&E has not changed substantially since the cost of capital was last reviewed for 1989. However, as part of our overall assessment of risk, we will recognize an incrementally higher level.

After considering all the evidence of the market conditions, trends, and the quantitative models presented by the parties, we conclude that a 12.90% return on common equity is just and reasonable for PG&E in 1990. While this return is somewhat above the range of the parties' DCF model results, it is more in line with the RPM and CAPM model results even after consideration is given to the problems with PG&E's methodology noted earlier. This return gives recognition to the elimination of NRSA and the potential risk that adds to PG&E's gas operations, as well as the overall level of business risk facing PG&E. In establishing this return, we are recognizing that the overall level of inflation and interest rates appear to be more favorable than when we established PG&E's return for 1989 one year ago, but also that there is some uncertainty and volatility in in financial markets.

E. Adopted Cost of Capital

The 12.90% adopted return on common equity produces an overall rate of return of 10.96% for 1990, as shown in the following table depicting the adopted cost of capital:

PG&E'S Adopted Cost of Capital

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	47.00%	9.32%	4.38%
Preferred Stock	6.25	8.79	0.55
Common Equity	46.75	12.90	6.03
TOTAL	100.00%		10.96%

F. Implementation

PG&E proposes that the change in revenue requirement resulting from its requested cost of capital be allocated to rates by class and spread in a manner consistent with the revenue allocation and rate design principles adopted in its 1990 general rate case (A.88-12-005) and its pending 1989 Energy Cost Adjustment Clause proceeding (A.89-04-001). We will provide in our order that the adopted cost of capital for PG&E's 1990 test year be implemented as proposed by PG&E.

VI. Southern California Edison Company

A. Background

In its application, Edison requests a return on equity of 13.75% and an overall rate of return of 11.27%. The estimated increase in the utility's revenue requirement incorporating the 11.27% rate of return is $62 million, or 1.0%. Prior to the hearings, Edison distributed revised testimony in which it lowered its requested return on equity from 13.75% to 13.25%. Edison requests that its authorized capital structure be the same as that authorized in the previous financial attrition proceeding.

Edison requests that the proposed capital cost factors for 1990 be reflected in rates effective January 1, 1990 by incorporation with its 1990 attrition year advice letter filing.

Presently authorized and requested rates of return are depicted in the following tables; DRA's recommendation is also shown:

Edison's Present Authorization
(D.88-12-094)

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	48.00%	9.30%	4.46%
Preferred Stock	6.00	7.84	0.47
Common Equity	46.00	13.00	5.98
TOTAL	100.00%		10.91%

Edison's Request*

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	48.00%	9.01%	4.32%
Preferred Stock	6.00	7.75	0.47
Common Equity	46.00	13.25	6.10
TOTAL	100.00%		10.89%

* Updated to reflect the September 1989 DRI forecast.

DRA's Recommendation*

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	48.00%	9.01%	4.32%
Preferred Stock	6.00	7.75	0.47
Common Equity	46.00	12.15	5.59
TOTAL	100.00%		10.38%

* Updated to reflect the September 1989 DRI forecast.

Edison presented the testimony of its Assistant Treasurer, Alan J. Fohrer, and its Manager of Financial Planning, C. Alex Miller. DRA presented the testimony of Edwin Quan, and FEA's witness Legler addressed the utility's cost of equity.

B. Capital Structure

There is no dispute over Edison's proposed capital structure for 1990, which is the same as that authorized for 1989. DRA concludes that the proposal is reasonable and within the range of optimal as defined in DRA's optimal capital structure study. The long-term debt and preferred stock ratios are within the ranges of 44% to 52% and 5% to 10%, respectively, recommended by FEA for electric utilities. Therefore we will adopt the proposed structure consisting of 48.00% long-term debt, 6.00% preferred stock, and 46.00% common equity for 1990.

C. Cost of Long-Term Debt and Preferred Stock

Although Edison maintains that DRA's estimated cost of embedded debt for 1990 is likely to understate the company's true interest cost due to its reliance on the DRI Control forecast, it accepts DRA's estimate. There is no issue involving bond rate additives since Edison's bond rating is Aa2/AA, and no other party addressed Edison's embedded debt costs. We will adopt the 9.01% cost of debt factor as shown in late-filed Exhibit 40, which reflects DRI's September 1989 Control interest forecast. Edison's 7.75% cost of preferred stock is not disputed and should be adopted for 1990.

D. Return on Common Equity

The only issue involved in determining Edison's 1990 cost of capital is the appropriate return on common equity for Edison in 1990. The following table summarizes the position of each party:

Party	Recommended Return
Edison	13.25%
DRA: Recommended range	11.90% - 12.40%
DRA: Specific Recommendation	12.15
FEA: Recommended range	11.80% - 12.30%
FEA: Specific Recommendation	12.10

Edison, DRA, and FEA submitted testimony on the results of various financial models which they used as a starting point in

developing their return on common equity recommendations. The following table summarizes the model results presented by witnesses Miller, Quan, and Legler:

Model	Party	Range
DCF	Edison	12.22% - 13.72%
	DRA (Group of 21)*	11.78 - 12.32
	DRA (Company-specific)*	11.63 - 12.17
	FEA (Group of 19)	11.1 - 11.8
	FEA (Company-specific)	10.8 - 12.3
RPM	Edison	11.52 - 13.12
	DRA (Group of 21)	11.76 - 12.43
	FEA (Long-term premiums)	12.8
	FEA (5 year premiums)	11.6 - 11.7
CAPM	Edison**	13.01 - 13.10
	DRA (Group of 21)	12.67 - 12.70
	DRA (Company-specific)	12.97 - 13.01

* DRA recommends that in view of the proposed merger of Edison and SDG&E and its potential effects on the market data underlying the DCF analysis, consideration be given to the comparable group results as well as company-specific results.

** Edison presented its CAPM model analysis as a version of the RPM model. For consistency of presentation we have shown Edison's CAPM results separately.

Edison believes that because its DCF model analysis reflects company-specific stock information, the effect of its non-regulated subsidiaries on its stock price results in the 7.72% dividend yield component of its DCF analysis being understated. Edison believes the effect of the Edison-SDG&E merger proposal on its stock price also results in a downward bias in its DCF results.

Edison's DCF model incorporates an estimated dividend growth range of 4.5% to 6.0%. The lower end of this range reflects Edison's judgements of eight analysts' growth forecasts which range from 3.9% to 4.8% and average 4.2%. The upper end of the range reflects historical dividends growth rates ranging from 6.19% (five-year average) to 8.05% (ten-year average). Edison believes

that the analysts' forecasts may be distorted because they only go out two years and because of potential effects of the merger. Edison believes that historical performance is a good measure of future performance.

FEA notes that Edison's DCF model would have yielded a lower-limit estimate of approximately 12% if the average forecast growth rate of 4.2% instead of 4.5% had been used. FEA also points out that Edison acknowledges that the historical growth rate of 6% or more depends on significant increases in its payout ratio. FEA believes that sustainable growth rates which do not require indefinitely increasing payout ratios should be used in the DCF model. Finally, FEA believes there is circularity involved in using historical growth rates, noting that as long as high growth rates in the past can be demonstrated, high required returns for the future are "documented".

Edison criticizes DRA's analysis for failing to adjust the company-specific DCF results for the merger proposal's impact. Edison also criticizes DRA's comparable group analysis because of the possible effects of diversification on the dividend yields of those companies. Edison notes that two thirds of the utilities in DRA's comparable group are holding companies or have non-regulated subsidiaries. Edison notes further that one third of the companies used by FEA in its comparable group DCF analysis are holding companies.

We agree with DRA and FEA that it is appropriate to consider comparable utilities as well as company-specific information when applying the DCF model. This is particularly the case when, as here, there are known problems such as the pending merger affecting the company-specific analysis. As DRA's witness Quan testified, group comparisons serve as a check on expected returns for a single company and mitigate measurement errors in the components of the financial models. We acknowledge there are problems with the group comparison approach, especially in an era

of diversification. It is for this reason that care must be exercised in interpreting model results and in not placing too much reliance on any one model or any one version of a model.

We give little weight to the criticism that FEA and DRA have failed to make adjustments for the merger effects or the non-regulated activities of Edison. We note that in evaluating the DCF results for Edison, DRA not only recommended examination of comparable group results, but also considered the impact of the merger proposal on both Edison's and SDG&E's company-specific dividend yields. DRA concludes that Edison's yield has remained somewhat stable at around 7.5% over the last year and a half, whereas SDG&E's yield has declined. Edison has not demonstrated that any downward bias in the DCF results is substantial. Further, as FEA observes, if non-regulated activities support higher stock prices, it must be as a result of anticipated dividends attributable at least in part to such activities.

We have already indicated our view that historical growth rates can be given some weight in the DCF model, but only if other measures of growth are also considered. In the case of Edison, it appears that historical growth rates are not likely to be sustained without significant changes in the payout ratio. They are above the growth forecasts of each of the eight stock analysts. We conclude that the 6% estimate of the growth components is likely to overstate reasonable expectations of investors. Even with due consideration given to the possible downward bias associated with the merger and non-regulated activities, we conclude that little weight should be given to the implication of Edison's DCF analysis that its return on equity could reasonably be set as high as 13.72%.

Edison believes that its RPM and CAPM results may be understated because they incorporate DRI interest forecasts. FEA objects to Edison's RPM analysis because it uses historical premiums and does not distinguish expected and realized risk

premiums. FEA objects to Edison's CAPM analysis as well, noting both that it uses adjusted betas from Value Line which overstate actual betas and that it uses a market premium which is inconsistent with use of Value Line betas. We believe there is some merit to each of these observations, but note that the model results are generally consistent with those of the other parties.

As part of his overall evaluation of the required returns on equity for SoCalGas, PG&E, and SDG&E, FEA's witness Legler ranked these four utilities according to their relative riskiness. His assessment of risk was based on an analysis of six indicators: proposed equity ratios, bond ratings, long-term interest coverage, betas, safety ratings, and financial strength ratings. The latter three indicators are taken from Value Line. Legler concluded that Edison is the least risky of the four major energy utilities, and this conclusion is reflected in a lower return on equity recommendation for Edison than for the other utilities.

Edison argues that five of the six indicators used by Legler are of little value, noting the following:

1. The Value Line indicators represent holding companies, and they do not account for non-regulated activities, PG&E's Diablo Canyon plant, or the proposed Edison-SDG&E merger.

2. The proposed equity ratios do not properly measure risk because of their exclusion of short-term debt and capital leases. These factors are considered by bond rating agencies when assessing financial risk.

3. Long-term interest coverage incorporates the impact of non-regulated subsidiaries, and FEA's coverage calculation excludes permanent short-term debt and capital leases.

We believe there is merit in the overall approach taken by FEA in ranking the relative risk of the utilities. Despite the problems associated with any one risk indicator, it is noteworthy

that six separate indicators were used. Further, FEA's ranking is generally consistent with our qualitative risk assessments. We also note that FEA's ranking of relative risk is not inconsistent with a ranking based only on bond ratings, the one rating factor Edison does not object to. We conclude that FEA's ranking can appropriately be considered along with all of the other valid indicators of investors' required returns, but should not be relied on exclusively in the final analysis.

Edison states that its interest coverage ratio will be 3.4 if its requested return on equity of 13.25% is adopted. According to Edison's testimony, this represents a reduced coverage which could jeopardize its AA bond rating. Standard and Poor's minimum coverage criteria for an AA rating is 3.5. While a double A bond rating is of benefit to both shareholders and ratepayers, holding all other factors constant, we find no basis for establishing a return on equity of 13.25% in order to maintain coverage of 3.4 times when other factors have persuaded us that a lower return is reasonable. As DRA has noted, since the capital structure we are adopting is the same as the currently adopted structure, the level of financial risk facing Edison has not changed significantly since the cost of capital was last reviewed for 1989.

After considering all the evidence of the market conditions, trends, and the quantitative models presented by the parties, we conclude that a 12.85% return on common equity is just and reasonable for Edison in 1990. This return gives recognition to the overall level of business risk facing Edison, including such conditions in the electric utility industry as third party generation and bypass. We are also recognizing that the overall levels of inflation and interest rates appear to be more favorable than when we established Edison's return for 1989 one year ago, but at the same time there is some uncertainty and volatility in financial markets. We believe this return on equity is more

reflective of the range of returns indicated by the parties' financial model results than any of the proposed returns, and that it is sufficient to allow Edison to maintain adequate interest coverage.

By today's order we are establishing returns on equity of 12.90% for PG&E and SDG&E. Although Edison has a more leveraged ratemaking capital structure than either PG&E's or SDG&E's, our determination of returns on equity is based on our assessment of overall levels of risk, including but not limited to financial risk.

E. Adopted Cost of Capital

The 12.85% adopted return on common equity produces an overall rate of return of 10.70% for 1990, as shown in the following table depicting the adopted cost of capital:

Edison's Adopted Cost of Capital

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	48.00%	9.01%	4.32%
Preferred Stock	6.00	7.75	0.47
Common Equity	46.00	12.85	5.91
TOTAL	100.00%		10.70%

VII. San Diego Gas and Electric Company

A. Background

SDG&E requests adoption of a 13.75% return on equity for 1990. The utility also requests adjustments to its embedded debt and preferred stock costs and to its authorized capital structure. Based on the overall rate of return of 11.35% sought in the application, SDG&E seeks a revenue requirement increase for 1990 of $18.704 million for its electric department, $2.361 million for its gas department, and $2 thousand for its steam department. The respective percentage increases are 1.58%, 0,70%, and 0.11%.

SDG&E's presently authorized and requested rate of return, and DRA's rate of return recommendation, are depicted in the following tables:

SDG&E's Present Authorization
(D.88-12-094)

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	45.75%	9.23%	4.22%
Preferred Stock	6.25	6.97	0.44
Common Equity	48.00	13.00	6.24
TOTAL	100.00%		10.90%

SDG&E's Request*

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	44.25%	9.13%	4.04%
Preferred Stock	6.25	7.18	0.45
Common Equity	49.50	13.75	6.81
TOTAL	100.00%		11.30%

* Late-filed Exhibit 40.

DRA's Recommendation*

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	45.75%	9.08%	4.15%
Preferred Stock	6.25	7.18	0.45
Common Equity	48.00	12.15	5.83
TOTAL	100.00%		10.43%

* Updated to reflect the September 1989 DRI forecast.

SDG&E presented the testimony of its Director of Finance and Assistant Treasurer, Malyn K. Malquist, and its Manager of Financial Analysis and Forecasting, Richard A. Krumvieda. DRA presented the testimony of Edwin Quan, and FEA's witness Legler addressed the utility's cost of equity. In its brief, the City of

San Diego recommends adoption of DRA's recommended 12.15% return on equity recommendation, and opposes SDG&E's request to change its authorized capital structure.

B. Capital Structure

SDG&E proposes a ratemaking capital structure consisting of 44.25% long-term debt, 6.25% preferred stock, and 49.50% common equity. DRA recommends the adopted ratios be 45.75% long-term debt, 6.25% preferred stock, and 48.00% common equity, the ratios adopted in last year's proceeding. (SDG&E proposed an equity ratio of 51.00% in that proceeding, but we authorized 48.00% based in large part on comparisons with other utilities.) As noted, City of San Diego opposes the utility's proposed capital structure, and further recommends that if the equity ratio is increased from the current authorization, the authorized return on equity should be lowered accordingly to reflect the reduced risk associated with such a capital structure.

SDG&E asks that in evaluating its equity ratio in comparison with the other electric utilities, we recognize the concept of "total ratemaking capital structure", and that we also consider its financial capital structure. According to SDG&E, the total ratemaking capital structure includes all long-term capitalization considered by the Commission in all regulatory proceedings. While the cost of long-term debt associated with rate base assets is recovered through the cost of capital which is authorized in proceedings such as this one, a significant portion of SDG&E's capitalization in the form of long-term lease obligations is recovered as expense in general rate cases and in Energy Cost Adjustment Clause (ECAC) proceedings. The capital and interest expense for the Encina 5 Power Plant is in the form of a long-term lease and recovery of that expense occurs through the Commission's authorization of O&M expense. Since lease obligations are not included in the debt ratio authorized in this proceeding, SDG&E argues the corresponding equity ratio is overstated in

relation to the total ratemaking equity ratio. Also, since the relation between rate base equity ratios and total ratemaking equity ratios varies among utilities, SDG&E argues that inter-utility comparisons of rate base equity ratios are not fair.

To illustrate its contention that its capital structure is not out of line with the California electric utilities, SDG&E presented an analysis of actual year-end 1988 capital structures for the three utilities. On the basis of rate base capital structures, SDG&E, Edison, and PG&E had equity ratios of 49.7%, 46.6%, and 46.5%, respectively. On the basis of total ratemaking capital structures, however, the three utilities had more similar equity ratios of 45.8%, 46.6%, and 44.9%. SDG&E also asserts its 1990 forecasted total ratemaking equity ratio of 46.1%, which corresponds to its requested rate base equity ratio of 49.5%, compares favorably with the average 1988 total ratemaking equity ratio of 45.2% for A-rated utilities.

SDG&E states that its requested 49.5% equity ratio for 1990 corresponds to a financial equity ratio of 44.6%. SDG&E believes that its proposal is also shown to be reasonable on the basis of comparisons with financial capital structures of PG&E, Edison, and the average for single A rated utilities, as shown in the following table:

Financial Capital Structures

	1988 Average "A" Utilities	1990-Requested		
		SDG&E	Edison	PG&E
Long-term debt:	49.4%	49.8%	52.8%	50.8%
Preferred Stock:	6.8	5.6	5.3	5.8
Common equity:	43.8	44.6%	41.9	43.4

SDG&E maintains that failure to consider the distinction between rate base and total ratemaking equity ratios will provide an incentive for utilities not to use long-term lease debt as a source of capital. According to SDG&E, if the Commission does not

fully account for the distinction, it will not have an opportunity to earn its authorized return on all of its outstanding utility equity simply because it used lease debt instead of mortgage bond debt as a source of capital.

DRA's witness Quan concluded that for purposes of determining the appropriate rate of return on rate base, a ratemaking capitalization which reflects only amounts supporting rate base assets should be considered, and that to include other amounts of capital which have associated costs recovered through other rate mechanisms could result in double counting. DRA believes that SDG&E's request for a 49.5% common equity ratio is out of line with those of the other utilities and is therefore excessive.

Where SDG&E compared its forecasted 1990 financial equity ratio of 44.6% with Edison's 41.9% and PG&E's 43.4%, DRA believes that SDG&E's total ratemaking equity ratio of 46.1% should be used to make the comparison with the other utilities. DRA explains that the 44.6% figure is based on SDG&E issuing 3.1% short-term debt in 1990, and points out that the utility did not have short-term debt outstanding at the end of 1987 or 1988. DRA notes however that even if short-term debt is included and the 44.6% financial equity ratio is used, SDG&E's ratio is relatively higher.

DRA recommends that a a capital structure with an equity ratio no greater than the 48.0% found reasonable in the last decision be adopted. DRA believes that while this is still relatively high compared to other utilities, it is reasonable since it approximates DRA's recommended target level defined in its optimal capital structure study. If the 49.5% ratio is adopted, DRA submits that a lower return on equity is warranted.

In weighing the arguments concerning SDG&E's capital ratio, we find the balance tipped in favor of SDG&E's position. The evidence is uncontroverted that SDG&E's use of long-term leases has been of benefit to ratepayers. The use of such leases can provide a valuable, low-cost financing option and SDG&E's decision to follow this route demonstrates this fact.

DRA's proposal to adjust SDG&E's equity ratio is predicated on the intricacies of ratemaking rather than any compelling policy. We reflect the costs of lease financing as an operating cost and not a capital cost, notwithstanding the true "capital" nature of those costs. To then say that SDG&E's capital structure, purged of lease financing, is too equity laden is to penalize SDG&E for our ratemaking practice. Taken as a whole, SDG&E's financial planning appears to be reasonable; DRA even cites SDG&E's strong financial performance and rating in its arguments concerning return of equity. We also believe that DRA's position could discourage further use of long-term leases despite their benefits. We specifically reject DRA's assertion that inclusion of lease financing in evaluating SDG&E's capital structure will result in double counting of financing costs.

We conclude from all of the above that SDG&E's proposed equity ratio of 49.50% is reasonable and should be adopted. We will adopt a capital structure of 44.25% long-term debt, 6.25% preferred stock and 49.50% common equity.

C. Cost of Long-Term Debt and Preferred Stock

As shown in late-filed Exhibit 40, SDG&E and DRA disagree on the estimated cost of embedded debt for 1990. SDG&E's 9.13% estimate is based on its forecast of a 10% yield on AA utility bonds in 1990 and its 35 basis point additive to reflect it lower

credit rating. SDG&E used the 10.35% result for estimating the cost of its planned debt issuance in 1990.

DRA used DRI's September, 1989 Control interest forecast of 8.64% for AA rated utility bonds in 1990, and added its recommended risk premium of 15 basis points. Combining the resulting 8.79% estimate for 1990 debt issuance with the historical embedded cost yields an overall cost of embedded long-term debt of 9.08%. Since we have adopted DRA's recommendation on the additives for estimating the debt cost of utilities with other than AA bond ratings, and we have decided to use the September 1989 DRI Control forecast for determining long-term debt costs, we will adopt 9.08% as the long-term debt cost for 1990.

SDG&E's 7.18% cost of preferred stock is not disputed and should be adopted for the 1990 attrition year.

D. Return on Common Equity

Also at issue is the appropriate return on common equity for SDG&E's 1990 attrition year. The following table summarizes the position of each party:

Party	Recommended Return
SDG&E	13.75%
DRA: Recommended range	11.90% - 12.40%
DRA: Specific Recommendation*	12.15%
FEA: Recommended range	11.80% - 12.60%
FEA: Specific Recommendation	12.20%

*City of San Diego supports DRA's recommendation.

SDG&E, DRA, and FEA submitted testimony on the results of various financial models which they analyzed in developing their recommended return on common equity. The following table summarizes the model results presented by witnesses Krumvieda, Quan, and Legler:

Model	Party	Range
DCF	SDG&E (Group of 9)	12.0 % - 12.7 %
	DRA (Group of 21)*	11.78 - 12.32
	DRA (Company-specific)*	10.44 - 10.98
	FEA (Group of 9)	10.9 - 11.5
	FEA (Company-specific)	10.5 - 11.8
RPM	SDG&E (Group of 24)	13.9 - 14.9
	DRA (Group of 21)	11.76 - 12.43
	FEA (Long-term premiums)	12.2 - 12.6
	FEA (5 year premiums)	11.0 - 11.1
CAPM	DRA (Group of 21)	12.67 - 12.70
	DRA (Company-specific)	12.59 - 12.63

* Although it presented the company-specific results of the DCF analysis for SDG&E, DRA recommends that in view of the proposed merger of Edison and SDG&E and its potential effects the underlying data, the appropriate return is best estimated by use of the results from the comparable electric group.

SDG&E accounted for the effects of merger activity in its DCF analysis by using group comparisons for stock prices for periods after May 1988. SDG&E notes that FEA's company-specific DCF analysis was not adjusted for merger effects. FEA points out in response that it recognizes the merger effects as a problem and for that reason has used a group comparison DCF analysis as well.

SDG&E criticizes FEA's and DRA's DCF analysis for measuring stock prices over "relatively short" periods of three months. As noted by FEA, however, we have previously recognized that the use of three-month average stock prices is appropriate to temper day-to-day volatility in prices.

SDG&E's witness Malquist acknowledged that based on conditions prevailing at the time of the hearings, a return on common equity of 13.25% would be appropriate, assuming the utility's proposed common equity is adopted. Malquist also indicated that interest rates could change by the time we reach a decision in this matter. FEA notes that simple updating of the interest rate data in SDG&E's financial models would yield lower

required returns on equity. City of San Diego concludes that SDG&E's return on equity should be at least 100 basis points below the company's request of 13.25%, on the basis of more current interest rates.

FEA also criticizes SDG&E's RPM analysis because of its use of simple average risk premiums and the assumption that the premium will remain constant regardless of changes in rates. FEA witness Legler believes that risk premiums may be declining. We agree that less reliance should be placed on SDG&E's RPM model than the other model results presented by the parties, and conclude in particular that the 14.9% upper limit of SDG&E's range of results likely overstates investor requirements.

SDG&E refers to various business risks which it faces. These include the uncertainty of recovery of purchased power costs over the life of a contract with Portland General Electric and resource planning risk associated with financing needs created by new construction requirements. City of San Diego argues that with respect to potential disallowance of purchased power costs, any reasonable business dealings by SDG&E will be allowed by this Commission. As to risks associated with new construction, City of San Diego notes that growth can also be viewed as a strength by investors. We will recognize an incremental change in SDG&E's overall business risk as a result of the foregoing as well as our recognition of the elimination of the NRSA as discussed earlier.

City of San Diego states that the Federal Energy Regulatory Commission has set a benchmark return on equity of 12.44% for the period from May 1, 1989 to July 1, 1989. SDG&E as well as Edison believe such reference is inappropriate and should not be relied on. We agree. The benchmark is a general guideline that does not specifically apply to individual utilities.

After considering all the evidence of the market conditions, trends, and the quantitative models presented by the parties, we conclude that a 12.90% return on common equity is just

and reasonable for SDG&E in 1990. While this return is at or above the upper limit of the financial model results, except SDG&E's RPM analysis, it gives recognition to the overall level of business and financial risk facing SDG&E, including our adopted capital structure. We are also recognizing that the overall levels of inflation and interest rates appear to be more favorable than when we established SDG&E's return for 1989 one year ago, but at the same time there is some uncertainty and volatility in financial markets.

E. Adopted Cost of Capital

The 12.90% adopted return on common equity produces an overall rate of return of 10.86% for 1990, as shown in the following table depicting the adopted cost of capital:

SDG&E's Adopted Cost of Capital

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	44.25%	9.08%	4.02%
Preferred Stock	6.25	7.18	0.45
Common Equity	49.50	12.90	6.39
TOTAL	100.00%		10.86%

F. Implementation

SDG&E proposes to implement the cost of capital authorized in this proceeding in conjunction with its 1990 operational attrition advice letter filing. The proposed rate changes submitted with the application were developed using the currently adopted rate design and revenue allocation procedures. SDG&E notes that the proposed electric rates incorporate a sales forecast which is consistent with the forecast filed with A.88-12-035 (for authority to merge SDG&E and Edison), but which is higher than the currently adopted electric sales forecast. SDG&E states that it has no objection to deferring the electric rate changes to coincide with the next electric rate change scheduled for May 1, 1990 under the Energy Cost Adjustment Clause (ECAC).

DRA recommends the following:

> "[T]hat the electric rate change resulting from SDG&E's 1990 attrition authorized rate of return be effective as of January 1, 1990, but that the rates be adjusted in conjunction with SDG&E's May 1, 1990 ECAC decision and the adopted rate design."

SDG&E concurs with DRA's proposal to defer the electric rate changes to May 1, 1990 with the understanding that under DRA's proposal, the electric margin change resulting from the authorized rate of return would be effected on January 1, 1990.

In their comments on the ALJ's proposed decision, both SDG&E and DRA specifically proposed using the ERAM balancing account to record over- or undercollections resulting from implementing the electric margin change effective January 1, 1990 and deferring the rate changes to May 1, 1990. Since the parties are in agreement on a specific mechanism, and ratepayers will benefit by reducing the frequency of rate changes, we will adopt the proposal.

VIII. Southwest Gas Corporation

A. Background

In its application, Southwest requests a return on equity of 14.0% and an overall rate of return of 12.46%. The revenue requirement increase needed to reach that rate of return is $373,427 for its Southern California Division and $49,753 for its Northern California Division. Southwest requests authorization to revise its rates based on the returns effective January 1, 1990. Southwest's presently authorized and requested rate of return, and DRA's recommended rate of return, are depicted in the following tables:

Southwest's Present Authorization
(D.88-12-081)

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	50.00%	11.21%	5.61%
Preferred Stock	5.00	9.57	0.48
Common Equity	45.00	13.00	5.85
TOTAL	100.00%		11.94%

Southwest's Request*

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	50.00%	11.35%	5.68%
Preferred Stock	5.00	9.57	0.48
Common Equity	45.00	14.00	6.30
TOTAL	100.00%		12.46%

* Late-filed Exhibit 40.

DRA's Recommendation*

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	50.00%	10.56%	5.28%
Preferred Stock	5.00	9.56	0.48
Common Equity	45.00	12.30	5.54
TOTAL	100.00%		11.30%

* Late-filed Exhibit 40.

Southwest presented the testimony of its Treasurer, Andrew B. Laub, and DRA presented the testimony of Edwin Quan.

B. Capital Structure

Southwest notes that its proposed capital structure is comparable to the average for gas distribution utilities, and that it is the same as that approved by other jurisdictions served by Southwest as well as by us in the last general rate case. DRA concludes that the proposal is reasonable and within the range of

optimal as defined in DRA's optimal capital structure study. We will adopt the proposed structure consisting of 50.00% long-term debt, 5.00% preferred stock, and 45.00% common equity for 1990.

C. Cost of Long-Term Debt and Preferred Stock

Because Southwest does not plan to issue new long-term debt in 1989 or 1990, there is no forecast issue as there was for the other utilities. Late-filed Exhibit 40 shows that Southwest and DRA disagree on the utility's cost of long-term debt, but Southwest states in its brief that upon review of DRA's use of the workshop method for passing the tax benefits of call premiums to ratepayers, it accepts DRA's calculations showing the embedded cost will be 10.56% for 1990. Southwest also accepts the rationale underlying DRA's use of the workshop method. We will adopt the 10.56% cost of debt factor.

There is a minor difference of one basis point between Southwest's proposed 9.57% cost of preferred stock and DRA's recommended 9.56% cost. The difference appears to be due to DRA's slightly higher estimate of net capital at year-end 1988 and subsequent years, which is not explained. Because the adopted capital structure provides a preferred stock ratio of only 5%, the difference of one basis point is not reflected in the weighted cost of 0.48% due to rounding. We will adopt Southwest's estimate of preferred stock cost for the 1990 attrition year.

D. Return on Common Equity

The only remaining issue is the appropriate return on common equity for Southwest's 1990 attrition year. The following table summarizes the position of each party:

Party	Recommended Return
Southwest	14.00%
DRA: Recommended range	11.90% - 12.40%
DRA: Specific Recommendation	12.30

Southwest and DRA submitted testimony on the results of various financial models which they used in developing their recommended returns on common equity. The following table summarizes the model results presented by witnesses Laub and Quan:

Model	Party	Range
DCF	Southwest (Group of 13)	12.57%
	Southwest (Company-specific)	14.48%
	DRA (Group of 14)*	12.05 - 12.58
	DRA (Company-specific)	13.10 - 13.63
RPM	Southwest	16.94%
	DRA (Group of 14)	11.38 - 12.85
CAPM	DRA (Group of 14)*	12.51 - 12.56
	DRA (Company-specific)	12.97 - 13.01

* Recommended by DRA.

DRA presented the results of company-specific DCF and CAPM model analyses for Southwest as well as group comparisons. DRA recommends, however, that Southwest's return on common equity be based on consideration of the comparable group of 14 gas utilities. DRA notes that the company-specific analyses represent the diversified operations of Southwest Gas Corporation, including its nonutility services, and that Value Line has commented that any gains in earnings that Southwest enjoys from the gas distribution business may be overshadowed by poorer financial performance by its savings and loan subsidiary, PriMerit Federal Savings Bank.

Southwest objects to DRA's analyses because the utilities included in DRA's comparable group are in fact superior rated A and AA companies. Southwest has a bond rating of Baa-3/BBB. Southwest used selection criteria for developing a group of comparable utilities which were intended to include companies similar to Southwest in size when compared by number of utility customers served, revenues from gas sales, utility asset size, and volumes delivered. All of the 13 utilities selected by Southwest were included in a larger list of 37 gas distribution utilities which

derive at least 90% of their operating revenues from natural gas distribution. Southwest also disagrees with the DRA position that company-specific model analyses should be disregarded because of its nonutility operations, noting that its bond ratings were not changed after its aquisition of PriMerit.

Southwest agrees with DRA that overall business and financial risk has changed very little since its last cost of capital review. On the other hand, Southwest does not agree that short-term economic conditions such as lower interest rates represent different conditions which warrant a lower return on equity than the currently authorized return. Thus, Southwest requests that at a minimum we continue its authorized return of 13.0% for 1990.

We note that Southwest's group DCF result of 12.57%, representing utilities which are more nearly comparable than those considered by DRA, is virtually the same as the 12.58% upper limit of group DCF results measured by DRA. We conclude that DRA's use of larger utilities with higher bond ratings for comparison purposes may yield model results which are somewhat understated for Southwest.

On the other hand, we will not place much reliance on company-specific model results for Southwest, due to its diversified operations. Southwest's company-specific DCF analysis indicates a required return on equity which is almost 200 basis points higher than the return indicated by its comparable group analysis. DRA's company-specific results were more than 100 basis points higher than its group results. Even when we account for DRA's use of A and AA rated comparable utilities, we find no basis for concluding that investors require a return from Southwest which is 100 to 200 basis points higher than that indicated by the group analyses. The fact that the aquisition of PriMerit has not been accompanied by a change in bond ratings does not, alone,

demonstrate that investors perceive Southwest purely as a gas distribution utility.

We also give little weight to the RPM analysis presented by Southwest, which indicates a required return of 16.94%. This incorporates a risk premium of 5.99%, which was calculated by taking the difference between Standard and Poor's 500 stock market returns and the returns on Moody's Baa utility bonds. We are not persuaded that the returns required by utility equity investors can be measured by using the average stock market returns of all industries represented in the S&P 500.

After considering all the evidence of the market conditions, trends, and the quantitative models presented by the parties, we conclude that a 13.05% return on common equity is just and reasonable for Southwest in 1990. In doing so, we are recognizing that the overall levels of inflation and interest rates appear to more favorable than when we established Southwest's return for 1989 one year ago, but at the same time there is some uncertainty and volatility in financial markets. We are also recognizing Southwest's business and financial risks, including its lower bond rating.

E. Adopted Cost of Capital

The 13.05% adopted return on common equity produces an overall rate of return of 11.63% for 1990, as shown in the following table depicting the adopted cost of capital:

Southwest's Adopted Cost of Capital

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	50.00%	10.56%	5.28%
Preferred Stock	5.00	9.57	0.48
Common Equity	45.00	13.05	5.87
TOTAL	100.00%		11.63%

IX. Sierra Pacific Power Company

A. Background

SPPC requests a 14.0% return on equity and a gross revenue requirement increase of $506,000, or 1.3%, on a 1990 test year basis. SPPC's presently authorized and requested rate of return, and DRA's recommendation, are depicted in the following tables:

SPPC's Present Authorization
(D.88-12-094)

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	51.39%	8.65%	4.45%
Preferred Stock	6.68	7.74	0.52
Common Equity	41.93	13.15	5.51
TOTAL	100.00%		10.48%

SPPC's Request*

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	51.06%	8.47%	4.32%
Preferred Stock	6.55	7.74	0.51
Common Equity	42.39	14.00	5.93
TOTAL	100.00%		10.76%

* Late-filed Exhibit 40.

DRA's Recommendation*

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	51.06%	8.47%	4.32%
Preferred Stock	6.55	7.74	0.51
Common Equity	42.39	12.25	5.19
TOTAL	100.00%		10.02%

* Late-filed Exhibit 40.

SPPC presented the testimony of Anthony J. Karr and its return on equity witness, Charles E. Olson. DRA presented the testimony of Edwin Quan.

B. Capital Structure

SPPC's capital structure proposal includes an increase in its equity ratio from the currently authorized 41.93% to 42.39%, and reductions in its long-term debt and preferred stock ratios from 51.39% and 6.68% to 51.06% and 6.55% respectively. DRA characterizes the proposed structure as being not significantly different from that used to set the utility's rate of return for 1989. DRA concludes the proposal is reasonable and within the range of optimal as defined in its optimal capital structure study. The long-term debt and preferred stock ratios are within the ranges of 44% to 52% and 5% to 10%, respectively, recommended by FEA for electric utilities. We will adopt SPPC's proposed structure for 1990.

C. Cost of Long-Term Debt and Preferred Stock

SPPC used updated (August 1989) rate information obtained from the utility's remarketing agent to forecast the cost of floating rate debt issues, since DRI's forecast does not project variable rate debt costs. DRA agrees with this method, and the requested cost of long-term debt is not disputed. We will adopt the 8.47% cost of debt factor shown in late-filed Exhibit 40. SPPC's 7.74% cost of preferred stock, which is not disputed, should be adopted for the 1990 test year.

D. Return on Common Equity

At issue is the appropriate return on common equity for SPPC in 1990. The following table summarizes the position of each party:

Party	Recommended Return
SPPC	14.00%
DRA: Recommended range	11.90% - 12.40%
DRA: Specific Recommendation	12.25

SPPC and DRA submitted testimony on the results of various financial models which they used in the development of their recommended returns on common equity. The following table summarizes the model results presented by witnesses Olson and Quan:

Model	Party	Range
DCF	SPPC (Group of 10)	12.61% - 13.13%
	DRA (Group of 21)	11.78 - 12.32
	DRA (Company-specific)	11.40 - 11.94
RPM	SPPC	12.7
	DRA (Group of 21)	11.76 - 12.43
CAPM	DRA (Group of 21)	12.67 - 12.70
	DRA (Company-specific)	12.17 - 12.29

SPPC and DRA used similar dividend yields in their DCF analyses, but they disagree on the growth component of the model. SPPC used a range of 4.5% to 5.0% and DRA used a range of 3.5% to 4.0%. SPPC attributes the difference of 100 basis points to the different selection criteria used for the parties' comparable groups. Based on our review of the record, we believe the difference is largely explained by different emphases placed on historical growth rates:

1. SPPC's witness Olson calculated ten-year earnings and dividends growth rates of 4.7% and 5.2% respectively, and five-year growth rates of 1.3% and 4.5%, respectively. Based on consensus estimates published by the Institutional Brokers Estimate System (IBES), Olson estimated an average expected growth rate of 3.7%. Finally, Olson calculated a retention growth rate of 2.7%, noting that this estimate reflects poor 1988 results which investors would not expect to continue. Olson testified that his recommended range of 4.5% to 5.0% reflects his belief that investors expect electric utilities' earnings to improve substantially from past levels.

2. DRA's witness Quan calculated historical dividends and growth growth rates for electric utilities ranging from 3.89% to

5.77%. Forecasted growth rates considered by Quan ranged from 3.6% to 4.2%. Retention growth estimated by Quan for electric utilities was 4.04%.

It is apparent from the foregoing that SPPC places more reliance on continuation or resumption of historical growth rates than DRA does. We have already indicated our view that historical growth can be given some weight in the DCF model when other measures of growth are considered as well. In this case, the historical growth estimates are, in general, substantially greater than those forecasted by securities analysts and the retention rates of growth. We conclude that DRA's projected range of 3.5% to 4.0% is a more realistic estimate than SPPC's projected range of 4.0% to 5.0%.

Olson recommends that the rates of return on equity calculated using the financial models be increased by an 8% adjustment factor to reflect average financing costs of 4.7% and to offset market pressure which would drive the stock's value down to or below book value when new stock is issued. FEA's witness Legler believes there is in theory a need to set the return on book value somewhat above the market value cost of equity, but that determining the proper relationship is a highly complex problem. Factors which Legler indicated should be considered would include stock market conditions, volatility of the stock in question, the growth rate, the market to book ratio, how the company is financed, and whether new stock will be sold.

We recognize there may be a theoretical basis for such adjustments for new issues, but we are not persuaded that an 8% additive to the model results, which is in large part a matter of judgement, is justified. No other party has suggested such an approach, and as noted by Legler, determining the proper relationship involves consideration of a variety of factors. An additive of 8% would result in the addition of approximately 100 basis points to the authorized return on equity for the range of

model results calculated by the parties. We conclude on the basis of this record that such an additive is not justified for 1990. The record shows that SPPC has not issued stock since 1984, nor does it disclose that SPPC plans to do so in 1990.

Since the proposed capital structure is not significantly different from the currently adopted structure, DRA believes that the level of financial risk facing SPPC has not changed significantly since the cost of capital was last reviewed for 1989. DRA does recommend that SPPC's return on equity be set higher than the return for the other electric utilities in recognition of greater relative risk. DRA notes that SPPC is more leveraged than the other electric utilities, and that on the basis of 1988 revenues, SPPC is the smallest of the utilities analyzed, with approximately $408 million in revenues compared to an average of $2.9 billion for the electric utility group and an average of $5.3 billion for the California electric utilities.

After considering all the evidence of the market conditions, trends, and the quantitative models presented by the parties, we conclude that a 13.00% return on common equity is just and reasonable for SPPC in 1990. In doing so, we are recognizing that the overall levels of inflation and interest rates appear to more favorable than when we established SPPC's return for 1989 one year ago, but at the same time there is some uncertainty and volatility in financial markets. By setting a return on equity which is higher than the return generally indicated by the results of the financial models, we are also recognizing SPPC's relative risk compared to the other electric utilities.

E. Adopted Cost of Capital

The 13.00% adopted return on common equity produces an overall rate of return of 10.34% for 1990, as shown in the following table depicting the adopted cost of capital:

SPPC's Adopted Cost of Capital

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	51.06%	8.47%	4.32%
Preferred Stock	6.55	7.74	0.51
Common Equity	42.39	13.00	5.51
TOTAL	100.00%		10.34%

F. Implementation

On August 16, 1989, SPPC filed its test year general rate case application, which was docketed as A.89-08-027. We will provide that the cost of capital factors adopted today shall be incorporated in the test year 1990 revenue requirement to be determined in conjunction with the general rate case.

X. Proposed Decision

The proposed decision of the ALJ was filed with the Commission and served upon all parties to the proceeding on November 6, 1989 in accordance with § 311(d) of the PU Code. We are taking action in this matter today because issuance of a Commission decision prior to December 1989 is necessary to assure that several pending matters which incorporate the adopted costs of capital are processed in an orderly fashion by the end of the year. The proposed decision was not filed and served 30 days prior to today as a result of the disruption of Commission operations which followed the earthquake of October 17, 1989. Our action today is taken in accordance with the provisions of PU Code § 311(d) under which the Commission may issue its decision sooner than 30 days following filing and service of the ALJ's proposed decision in the event of an unforeseen emergency situation.

Comments on the proposed decision were filed by parties in accordance with Article 19 of the Commission's Rules of Practice and Procedure and a ruling by the ALJ which required the comments

to be filed by November 16, 1989. Reply comments were not received. We have carefully considered the ALJ's proposed decision and the parties' comments, and have made modifications to the ALJ's proposed decision where appropriate.

Findings of Fact

1. By D.89-01-040 we removed consideration of cost of capital issues from general rate cases filed by SoCalGas, PG&E, Edison, SDG&E, Southwest, SPPC, and Pacific Power & Light Company, and established a separate, generic, annual cost of capital (ACC) proceeding.

2. The plan for ACC proceedings provides that the new rates will be implemented in conjunction with the utility's pending general rate case or its attrition rate adjustment filing as applicable.

3. A trigger mechanism for return on equity adjustments would not allow a full cost of capital review unless selected financial data change by more than a predetermined magnitude.

4. No party recommends implementation of a trigger mechanism at this time.

5. At workshops addressing methods to treat the tax savings created by the deductibility of the call premiums paid to bondholders when high-cost debt is prematurely retired, the participating utilities and DRA agreed in principle on a method by which they will record the call premiums at the combined federal and state tax rates in the year of refunding, with full amortization of the premiums and related expenses within a specified period using the straight-line method.

6. The workshop method results in a lower long-term debt cost for each of the energy utilities, and there is no dispute on its use for determining the cost of long-term debt.

7. By D.85-12-076 we directed utilities to use the DRI forecast for AA rated utility debt to estimate the cost of planned new debt issues, and indicated that utilities that do not have both

an Aa (Moody's) and AA (S&P's) rating should add a risk premium of no more than 50 basis points if appropriate.

8. From July 1988 to June 1989 the average spread between A and AA rated utility bonds was approximately 20 basis points. For 1988 the average spread was 23 basis points.

9. The average spreads over the last ten, five, and three year periods were 48, 32, and 29 basis points, respectively. The average spread for the five year period 1979-83 was 63 basis points.

10. In the first six months of 1989, the spread ranged from 14 to 27 basis points, and in five of those months the spread was the same as or less than that of the corresponding month in the previous year.

11. Utilities with an A rating will not necessarily incur debt costs as high as the single A rate for all new issues.

12. The offering yields and effective interest rates on six SoCalGas bond issues in 1986 and 1988 were, on average, lower than contemporaneous Moody's Aa utility bond yields.

13. A spread of 25 basis points for PG&E and SoCalGas is reasonably conservative in that it is five basis points above the most recent 12 month average spread of 20 basis points, and slightly above the 1988 calendar year average.

14. A spread of 15 basis points for SDG&E is reasonable in view of its bond rating.

15. There will be an opportunity to reevaluate the appropriate spread in each year's ACC proceeding.

16. The utilities acknowledge that the lower interest rates in effect and forecasted at the time of the hearings support returns on equity which are lower than those requested in their applications.

17. The DRI Control forecast for AA utility bonds for 1990 declined approximately 130 basis points from the April forecast of

9.96% to the July forecast of 8.67%. The September forecast was 8.64%

18. The July Wharton Economic Forecasting Associates (WEFA) forecast for AA utility bonds for 1990 was 9.8%.

19. FEA presented testimony showing that interest rates declined 60 to 110 basis points between December 1988 and late-July 1989, and Los Angeles determined that there has been a decline of 75 to 100 basis points in long-term rates.

20. Long-term 30-year Treasury Bond rates remained relatively flat in the first five months of 1989, then began to fall in the middle of May through July. Short-term three-month Treasury Bills rose from the beginning of the year through March, then began to decline in March through July.

21. Interest rate forecasts by PG&E, DRI, WEFA, and Meyer which generally show interest rates reaching a peak in early 1989, declining temporarily through mid-to-late 1990, and then increasing again in 1991, assume a recession or a slowing of economic growth, and no federal action to keep interest rates from dropping

22. Federal Reserve Board actions to reduce the federal funds rate and reductions in the prime rate in June are consistent with an economic slowdown.

23. A survey of 38 well-known economists concluded that for the remainder of 1989 and 1990 the economy would experience slow growth, and there would be no recession, little change in bond yields, lower short-term interest rates, and lower inflation.

24. The DRI Control forecast is inconsistent with the historical relationship between AA utility bonds and inflation rates, with an implied premium over forecasted inflation of 4.3% for 1990. Premiums as low as 4.3% have not prevailed since 1970.

25. In D.88-12-094 the Commission placed greater reliance on recorded interest rates and less reliance on the DRI forecast due to the subjective analysis underlying the DRI forecast and the

history of variations up to 181 basis points between the forecast and actual rates.

26. Interest rates can change by more than a hundred basis points in a matter of months.

27. The fact that the DRI Control forecast declined 130 basis points from April to July demonstrates the volatility of the forecast.

28. DRI assigns a higher probability to the Control forecast than to the Late-Recession scenario.

29. AA utility bond rates are not so volatile that predictions about them for the coming year are useless.

30. Interest rates are currently below the levels prevailing when we adopted the energy utilities' cost of capital for 1989, and are likely to remain below those levels during 1990, but there is some uncertainty and volatility in financial markets.

31. Interest rates in 1990 may be lower than they were expected to be in April 1989.

32. While equity investors are concerned with the overall return over the entire period they hold the stock, they will take into account the fact that returns on equity are regularly adjusted to reflect current economic conditions.

33. We conduct annual cost of capital reviews in part to recognize the volatility and unpredictability of interest rates.

34. The energy utilities have requested increases in their authorized returns on equity ranging from 25 to 100 basis points.

35. Increases in returns on equity are not justified on the basis of interest rates or interest rate trends.

36. To the extent that interest rates are determinative of the proper return on equity, reductions in the currently authorized returns in the range of 10 to 20 basis points are reasonable.

37. The use of the DRI forecast to calculate long-term debt cost is in accordance with the procedure we established in D.85-12-076 for financial attrition filings.

38. Parties in future cost of capital proceedings could benefit if a new methodology can be developed for incorporating interest rate trends in the annual cost of capital determinations.

39. The Supply Adjustment Mechanism (SAM) and the Gas Adjustment Clause (GAC) were eliminated May 1, 1988 for noncore gas customers, and replaced by the Negotiated Revenue Stability Account (NRSA) for a period of two years. The NRSA is scheduled for elimination on April 30, 1990.

40. The NRSA limits utility losses and gains in after-tax earnings to a range of 300 basis points above or below its authorized return on equity.

41. PG&E lost $17.8 million on noncore sales in the eight months following the initial phase-out of SAM. Without the NRSA, the loss would have been $25.1 million. PG&E could lose $47 million on noncore sales in 1989. Thus, the NRSA protected PG&E from more than $7 million ($25.1 - $17.8 million) in after tax losses in the first eight months following implementation of the gas restructuring program, and it may provide a greater savings in 1989.

42. Gas utilities can be expected to develop new strategies and benefit from current strategies such as long-term contracts with up-front demand charges to mitigate the risks associated with the elimination of the NRSA.

43. Elimination of the NRSA provides opportunities for enhanced profits as well as risks of losses.

44. Investors have been aware of the phasing out of protective mechanisms, as indicated by the Drexel Burnham Lambert report on PG&E in September 1988. To the extent that investors' perceptions of the associated risks are reflected in the financial model analyses, the risks may have already been quantified and incorporated in the parties' recommendations.

45. The elimination of the NRSA may result in an additional risk for the gas utilities that was not fully considered when their

equity returns were last established, but actual losses in the past do not indicate the probabilities of future losses or gains that can be expected for PG&E and the other gas utilities.

46. Restructuring of the gas industry due to federal and state policies has created new risks in the past few years, and such risks have previously been considered by this Commission and incorporated in its rate of return deliberations.

47. Electric utilities have experienced rapid growth in third-party capacity and sales, but the risks associated with this growth have not been shown to be significantly different from those previously considered in previous cost of capital reviews.

48. Third-party generation creates resource planning risks, but there are also benefits in the reduction of the utility's exposure to large baseload plant risks.

49. Retention of the ERAM and ARA mechanisms represents a reduction of risk for electric utilities compared to one year ago.

50. Bypass risk is mitigated by our policy of moving closer to EPMC (equal percentage of marginal cost), and the Commission's authorization of special contracts for large customers to encourage their remaining on the system.

51. There will normally be an interval of several weeks between the closing of the record in an ACC proceeding and the date of a decision by the Commission.

52. The adopted update procedure for ACC proceedings (D.89-01-040) was followed in this proceeding with the submittal of late-filed Exhibit 40, which included September interest rate forecasts.

53. Regulated energy utilities may not have adequate incentive to make efficient use of leverage without regulatory oversight of their capital structures.

54. Authorizing generic returns on common equity irrespective of differences in risk among utilities creates an incentive for

California utilities to hold more common equity financing than comparable risk-positioned utilities.

55. While leverage of nonregulated firms has increased since 1981, the opposite has been true of energy utilities.

56. Determining the OCS for a firm requires judgement as well as quantitative analysis.

57. DRA's LPM analysis produces meaningful results which can be used in conjunction with qualitative analysis and judgement to analyze capital structures.

58. Differences and variations in risks, the spread between debt and equity costs, the spread between costs of debt with different ratings, and changes in bond rating criteria will result in a different OCS for each firm and over time for the same firm.

59. Standard & Poor's guidelines for electric and combination utility debt include debt ratios of 39% to 46% for an AA rating and 44% to 52% for an A rating.

60. Spreads between yields on A rated electric utility bonds and higher rated bonds are currently so small that the reductions in debt required to achieve the higher ratings are not justified.

61. For electric utilities, ratings higher than single A are justified less than 15% of the time and have not been justified since the early 1980's.

62. Among industrial firms with investment grade bonds, 46% have an A rating, whereas only 4.9% of such firms have AAA ratings and only 16.2% have AA ratings.

63. DRA and FEA recommend capital structures which are consistent with maintenance of single-A bond ratings and no higher. SDG&E recommends structures based on criteria for both A and AA ratings.

64. SoCalGas' proposed capital structure for 1990, consisting of 45.00% long-term debt, 9.70% preferred stock, and 45.30% common equity, is not disputed.

65. DRA's 9.22% estimate of SoCalGas' embedded long-term debt cost for 1990 and its 7.31% estimate of preferred stock incorporate DRI's September; 1989 Control interest forecast for AA rated utility bonds, and risk premium spread of 25 basis points to reflect SoCalGas' single A bond rating.

66. Parties using the financial models to develop their return on equity recommendations cautioned against placing too much reliance on them, and recommended that the model results be tempered by judgement.

67. The DCF, RPM, and CAPM financial models are useful in establishing a range of required returns to consider in selecting the authorized return, and in evaluating trends of investor expectations when consistent assumptions and data sets are used in the analysis.

68. There may be an element of circularity in the historical growth version of the DCF model in that high historical levels of growth could, alone, incorrectly indicate a future need for high returns.

69. A 12.25% return on equity for SoCalGas will result in a coverage ratio of 3.19, which is barely adequate under Standard and Poors' guideline of 3 to 4.25 times annual interest expense and other fixed charges in order to maintain an A bond rating.

70. Bond rating agencies consider other factors besides interest coverage guidelines when rating bonds.

71. The level of financial risk facing SoCalGas has not changed significantly since 1989.

72. The potential for business risk faced by SoCalGas due to the proposed merger of SDG&E with Edison does not warrant an adjustment to the authorized return on equity for 1990.

73. A return on equity of 13.00% for SoCalGas' 1990 utility operations is reasonable.

74. Under our modified Rate Case Plan, gas rate design and revenue allocation issues are addressed in ACAPs, not in general rate cases or cost of capital filings.

75. PG&E's proposed capital structure for 1990, consisting of 47.00% long-term debt, 6.25% preferred stock, and 46.75% common equity, is not disputed.

76. DRA's 9.32% estimate of PG&E's embedded long-term debt cost for 1990 incorporates DRI's September, 1989 Control interest forecast for AA rated utility bonds, and a risk premium spread of 25 basis points to reflect PG&E's single A bond rating.

77. PG&E's estimated 8.79% cost of preferred stock is not disputed.

78. The use of comparable group data only in financial model analyses for PG&E is consistent with the Diablo Canyon Settlement Agreement, which precludes recognizing the impact of the settlement on future determinations of the utility's rate of return.

79. For its RPM and CAPM analysis, PG&E used DRI's Control and Late-Recession Forecasts to estimate 30-year Treasury bond rates and AA utility bond rates, and a 50 basis point spread to estimate the yields on A-rated utility bonds.

80. Value Line earnings projections include periods past 1990, the period we are concerned with for this proceeding.

81. Value Line forecasts used by PG&E are projected book returns, which could overstate the market returns required by investors.

82. Earned returns in the four quarters ending with the second quarter of 1989 do not indicate what investors require for 1990.

83. There is no assurance that the jurisdictions involved in a compilation of average authorized returns for the electric industry in the second quarter of 1989 use the same criteria as this Commission in authorizing returns on equity, that the

authorizations are reasonably current, or that they are reflective of comparable utilities.

84. PG&E will experience an incrementally higher level of financial risk in 1990 due to the 75 basis point reduction in its percentage of preferred stock and corresponding increase in long-term debt.

85. A return on equity of 12.90% for PG&E's 1990 utility operations is reasonable.

86. PG&E proposes that the change in revenue requirement resulting from its requested cost of capital be allocated to rates by class and spread in a manner consistent with the revenue allocation and rate design principles adopted in its 1990 general rate case (A.88-12-005) and its pending 1989 Energy Cost Adjustment Clause proceeding (A.89-04-001).

87. Edison's proposed capital structure for 1990, consisting of 48.00% long-term debt, 6.00% preferred stock, and 46.00% common equity, is not disputed.

88. As shown in late-filed Exhibit 40, the 9.01% cost of debt and 7.75% cost of preferred stock estimated for Edison are not disputed.

89. Edison's historical growth rates are not likely to be sustained without significant changes in the payout ratio, and a 6% estimate of the growth component of the DCF model is likely to overstate reasonable expectations of investors.

90. FEA's ranking of the relative risk of the energy utilities is generally consistent with our qualitative risk assessments.

91. A return on equity of 12.85% for Edison's 1990 utility operations is reasonable.

92. A significant portion of SDG&E's capitalization is in the form of long term lease obligations, the costs of which are recovered in ECAC and general rate case proceedings.

93. SDG&E's equity ratio is closer to those of the other electric utilities when comparisons are made on the basis of total ratemaking and financial capital structures instead of rate base capital structures.

94. If SDG&E issues 3.1% in short term debt, its 1990 equity ratio on a financial basis will be 80 basis points above the 1988 average for single A electric utilities, 270 basis points above Edison's and 120 basis points above PG&E's. If less short term debt is issued, the differences will be greater.

95. SDG&E's proposed capital structure consisting of 44.25% long term debt, 6.25% preferred stock, and 49.50% common equity is reasonable.

96. DRA's 9.08% estimate of SDG&E's embedded long-term debt cost for 1990 incorporates DRI's September, 1989 Control interest forecast for AA rated utility bonds, and risk premium spread of 15 basis points to reflect SDG&E's rating.

97. SDG&E's estimated 7.18% cost of preferred stock is not disputed.

98. A return on equity of 12.90% for SDG&E's utility operations is reasonable.

99. The proposals of SDG&E and DRA to defer implementation of electric rate changes are in agreement in that they both provide for using the ERAM balancing account to record any over- or undercollection resulting from the deferral.

100. Southwest's proposed capital structure for 1990, consisting of 50.00% long-term debt, 5.00% preferred stock, and 45.00% common equity, is not disputed.

101. DRA's 10.56% estimate of Southwest's long-term debt cost shown in Late-filed Exhibit 40 reflects DRA's use of the workshop method for passing the tax benefits of call premiums to ratepayers, and is not disputed by Southwest.

102. Southwest's proposed 9.57% cost of preferred stock is one basis point higher than DRA's estimate, but the difference is not reflected in the weighted cost of 0.48% due to rounding.

103. Value Line has commented that any gains in earnings that Southwest enjoys from the gas distribution business may be overshadowed by poorer financial performance by its savings and loan subsidiary, PriMerit Federal Savings Bank.

104. DRA's comparable group financial model analyses reflect large A and AA utilities.

105. Southwest has a bond rating of Baa-3/BBB.

106. Southwest's selection criteria for developing a group of comparable utilities were intended to include companies similar to Southwest in size when compared by number of utility customers served, revenues from gas sales, utility asset size, and volumes delivered.

107. Southwest agrees with DRA that overall business and financial risk has changed very little since its last cost of capital review.

108. Southwest's company-specific DCF analysis indicates a required return on equity which is almost 200 basis points higher than the return indicated by its comparable group analysis, and DRA's company-specific results were more than 100 basis points higher than its group results.

109. A return on equity of 13.05% for Southwest's 1990 utility operations is reasonable.

110. SPPC's proposed capital structure for 1990, consisting of 51.06% long-term debt, 6.55% preferred stock, and 42.39% common equity, is not disputed.

111. SPPC's proposed 8.47% cost of debt and 7.74% cost of preferred stock as shown in late-filed Exhibit 40 are not disputed.

112. In its DCF analysis, SPPC places more reliance on continuation or resumption of historical growth rates which are, in

general, substantially greater than those forecasted by securities analysts and the retention rates of growth.

113. In applying the results of financial model analysis, an adjustment factor to reflect financing costs and to offset market pressure which would drive the stock's value down to or below book value when new stock is issued is in theory needed, but determining the proper relationship is a highly complex problem.

114. SPPC is more leveraged than the other electric utilities, and on the basis of 1988 revenues, it is the smallest of the utilities analyzed, with approximately $408 million in revenues compared to an average of $2.9 billion for the electric utility group and an average of $5.3 billion for the California electric utilities.

115. A return on equity of 13.00% for SPPC's 1990 utility operations is reasonable.

116. The ALJ's proposed decision was not filed and served 30 days prior to today due to the disruption of Commission operations following the earthquake of October 17, 1989.

Conclusions of Law

1. The cost of capital factors adopted by this decision should be implemented in conjunction with each utility's 1990 attrition year filing or 1990 test year general rate case filing as applicable.

2. Parties may address the concept of a trigger mechanism for return on equity adjustments in future proceedings.

3. The workshop method for treating the tax savings associated with high-cost debt retirements should be used in calculating the cost of long term debt for the energy utilities.

4. For 1990, a 25 basis point premium should be added to forecasted AA utility bond yields in estimating the cost of new debt and preferred stock issues by SoCalGas and PG&E, and a 15 basis point premium should be used in the case of SDG&E.

5. Current interest rates and forecasted interest rates are significant, but subjective, determinants of appropriate returns on equity.

6. The DRI Control forecast should be considered only in conjunction with other interest rate forecasts and other economic indicators in determining appropriate returns on equity.

7. With annual cost of capital reviews, the primary concerns in establishing returns on equity for 1990 are the conditions expected to prevail in 1990.

8. Considering only interest rates and interest rate trends, the energy utilities' 1990 returns on equity should be reduced from currently authorized returns, but not by the 70 to 90 basis point range of reductions implied by DRA's and FEA's recommendations. The reductions should be in the range of 10 to 20 basis points on the basis of interest rates alone.

9. CACD should be directed to convene workshops with the energy utilities, DRA, and other parties to review the role of interest rate forecasts in cost of capital proceedings and to establish a consistent method of incorporating actual and forecasted interest rate information in cost of capital determinations.

10. The scheduled elimination of the NRSA is an additional risk which should be considered in determining the gas and combination utilities' returns on equity for 1990.

11. The update procedures established for ACC proceedings by D.89-01-040 should be followed under normal circumstances.

12. The Commission should oversee the management of capitalization to assure that efficient use of debt and preferred stock financing is made by the utilities, but in doing so, it should not adopt fixed, generic target capital structures which are presumed to be reasonable.

13. Utilities should provide justification of their financial and proposed ratemaking capital structures in cost of capital proceedings.

14. Utilities which have diversified into nonutility enterprises and/or adopted alternative corporate structures should be directed to show, in the next cost of capital proceeding, how their utility operations are insulated from the effects of their other enterprises.

15. SoCalGas' proposed 1990 capital structure should be adopted.

16. SoCalGas should be authorized a 9.22% cost of long-term debt and a 7.31% cost of preferred stock for 1990.

17. The results of financial models should be considered in conjunction with other quantitative and qualitative analyses in arriving at a final judgement in determining returns on equity.

18. Some weight can be given to the historical growth version of the DCF model when other measures of growth are also considered.

19. A 13.00% return on common equity, which results in an overall 10.75% return on rate base, should be adopted as just and reasonable for SoCalGas in 1990, based upon all of the evidence considered in this proceeding.

20. SoCalGas and the other utilities should incorporate the most recently adopted cost allocation and rate design principles in their filings implementing the adopted rates of return in rates.

21. PG&E's proposed 1990 capital structure should be adopted.

22. PG&E should be authorized a 9.32% cost of long-term debt and a 8.79% cost of preferred stock for 1990.

23. A 12.90% return on common equity, which results in an overall 10.96% return on rate base, should be adopted as just and reasonable for PG&E in 1990, based upon all of the evidence considered in this proceeding.

24. Edison's proposed 1990 capital structure should be adopted.

25. Edison should be authorized a 9.01% cost of long-term debt and a 7.75% cost of preferred stock for 1990.

26. Relative risk ranking analysis can be considered in conjunction with other analyses in arriving at a final judgement in determining returns on equity.

27. A 12.85% return on common equity, which results in an overall 10.70% return on rate base, should be adopted as just and reasonable for Edison in 1990, based upon all of the evidence considered in this proceeding.

28. Capital leases whose costs are recovered in other proceedings should be considered in evaluating ratemaking equity ratios.

29. SDG&E's proposed capital structure should be adopted for 1990.

30. SDG&E should be authorized a 9.08% cost of long-term debt and a 7.18% cost of preferred stock for 1990.

31. A 12.90% return on common equity, which results in an overall 10.86% return on rate base, should be adopted as just and reasonable for SDG&E in 1990, based upon all of the evidence considered in this proceeding.

32. Southwest's proposed 1990 capital structure should be adopted.

33. Southwest should be authorized a 10.56% cost of long-term debt and a 9.57% cost of preferred stock for 1990.

34. A 13.05% return on common equity, which results in an overall 11.63% return on rate base, should be adopted as just and reasonable for Southwest in 1990, based upon all of the evidence considered in this proceeding.

35. SPPC's proposed 1990 capital structure should be adopted.

36. SPPC should be authorized a 8.47% cost of long-term debt and a 7.74% cost of preferred stock for 1990.

37. A 13.00% return on common equity, which results in an overall 10.34% return on rate base, should be adopted as just and

reasonable for SPPC in 1990, based upon all of the evidence considered in this proceeding.

38. Under PU Code § 311(d), the Commission may issue its decision sooner than 30 days following filing and service of the ALJ's proposed decision in the event of an unforeseen emergency situation such as that following the October 17, 1989 earthquake.

O R D E R

IT IS ORDERED that:

1. Southern California Gas Company's (SoCalGas) adopted cost of capital for its 1990 test year is as follows:

SoCalGas' Adopted 1990 Cost of Capital

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	45.00%	9.22%	4.15%
Preferred Stock	9.70	7.31	0.71
Common Equity	45.30	13.00	5.89
TOTAL	100.00%		10.75%

2. SoCalGas' adopted 1990 test year rate of return, as shown in Ordering Paragraph 1, shall be used in conjunction with its pending 1990 general rate case proceeding decision and the most recently adopted cost allocation and rate design principles for the purpose of calculating revised rates for the 1990 test year.

3. Pacific Gas & Electric Company's (PG&E) adopted cost of capital for its 1990 test year is as follows:

PG&E's Adopted 1990 Cost of Capital

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	47.00%	9.32%	4.38%
Preferred Stock	6.25	8.79	0.55
Common Equity	46.75	12.90	6.03
TOTAL	100.00%		10.96%

4. PG&E's adopted 1990 test year rate of return, as shown in Ordering Paragraph 3, shall be used in conjunction with its pending 1990 general rate case proceeding decision, using the cost allocation and rate design principles adopted in that decision and its pending Energy Cost Adjustment Clause (ECAC) proceeding for the purpose of calculating revised rates for the 1990 test year.

5. Southern California Edison Company's (Edison) adopted cost of capital for its 1990 attrition year is as follows:

Edison's Adopted 1990 Cost of Capital

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	48.00%	9.01%	4.32%
Preferred Stock	6.00	7.75	0.47
Common Equity	46.00	12.85	5.91
TOTAL	100.00%		10.70%

6. Edison's adopted 1990 attrition year rate of return, as shown in Ordering Paragraph 5, shall be used in conjunction with its 1990 attrition year advice letter filing and the most recently adopted cost allocation and rate design principles for the purpose of calculating revised rates for the 1990 attrition year.

7. San Diego Gas & Electric Company's (SDG&E) adopted cost of capital for its 1990 attrition year is as follows:

SDG&E's Adopted 1990 Cost of Capital

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	44.25%	9.08%	4.02%
Preferred Stock	6.25	7.18	0.45
Common Equity	49.50	12.90	6.39
TOTAL	100.00%		10.86%

8. SDG&E's adopted 1990 attrition year rate of return, as shown in Ordering Paragraph 7, shall be used in conjunction with its 1990 attrition year advice letter filing and the most recently adopted cost allocation and rate design principles for the purpose of calculating revised gas and steam rates for the 1990 attrition

year. Electric rate changes shall be deferred pending disposition of SDG&E's current ECAC proceeding and adoption of an electric rate design in that proceeding. SDG&E shall reflect the 1990 attrition year rate of return in its Electric Department Authorized Base Rate Revenue effective January 1, 1990, and record any resulting revenue over- and undercollection in its Electric Revenue Adjustment Mechanism balancing account until electric rates are reset in the ECAC proceeding.

9. Southwest Gas Corporation's (Southwest) adopted cost of capital for its 1990 attrition year is as follows:

Southwest's Adopted 1990 Cost of Capital

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	50.00%	10.56%	5.28%
Preferred Stock	5.00	9.57	0.48
Common Equity	45.00	13.05	5.87
TOTAL	100.00%		11.63%

10. Southwest's adopted 1990 attrition year rate of return, as shown in Ordering Paragraph 9, shall be used in conjunction with its 1990 attrition year advice letter filing and the most recently adopted cost allocation and rate design principles for the purpose of calculating revised rates for the 1990 attrition year.

11. Sierra Pacific Power Company's (SPPC) adopted cost of capital for its 1990 test year is as follows:

SPPC's Adopted 1990 Cost of Capital

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	51.06%	8.47%	4.32%
Preferred Stock	6.55	7.74	0.51
Common Equity	42.39	13.00	5.51
TOTAL	100.00%		10.34%

12. SPPC's adopted 1990 test year rate of return, as shown in Ordering Paragraph 11, shall be used in conjunction with its

pending 1990 general rate case proceeding decision for the purpose of calculating revised rates for the 1990 test year.

13. SoCalGas, PG&E, Edison, SDG&E, Southwest, SPPC, and Pacific Power and Light Company shall address, in the next cost of capital proceeding, any of their nonutility operations which might affect their utility operations, and show how utility operations are insulated from the effects of their other enterprises for the purpose of determining the cost of capital for their utility operations.

14. The Commission Advisory and Compliance Division (CACD) shall schedule and chair a workshop not later than March, 1990 with the energy utilities, DRA, and other parties for the purpose of reviewing the role of interest rate forecasts in cost of capital proceedings and establishing a consistent method of incorporating actual and forecasted interest rate information in cost of capital determinations. A copy of this opinion shall be served on the CACD Director.

15. SoCalGas, PG&E, Edison, SDG&E, Southwest, SPPC, and Pacific Power and Light Company shall address the results of the workshops identified in Ordering Paragraph 14 in the next annual cost of capital proceeding.

This order is effective today.

Dated NOV 2 2 1989, at San Francisco, California.

G. MITCHELL WILK
President
FREDERICK R. DUDA
STANLEY W. HULETT
JOHN B. OHANIAN
PATRICIA M. ECKERT
Commissioners

I will file a partial concurrence and a partial dissent.

/s/ FREDERICK R. DUDA
Commissioner

I will file a written concurring opinion.

/s/ JOHN B. OHANIAN
Commissioner

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

Wesley Franklin

WESLEY FRANKLIN, Acting Executive Director

AB

Frederick R. Duda, Commissioner, concurring in part and dissenting in part.

I concur with many aspects of today's decision. For example, I agree that cost of capital determinations should be made on a utility by utility basis, since the generic approach fails to allow adequate consideration of either the individual financial and business risks facing each utility or the financial and business strengths possessed by each utility. I support the decision's reference to the potential benefits of preferred stock as a low cost source of capital, although I would have gone further to suggest that preferred stock guidelines should be seriously considered. I concur with the requirement that CACD hold workshops to address methods for incorporating interest rate trends in future cost of capital proceedings. And I agree that utilities should be required to address how their utility operations are insulated from their non-utility operations for the purpose of determining the cost of capital for their utility operations. These are but a few of the many things I like about today's decision.

I part company with my fellow commissioners, however, and must dissent when it comes to the determination of appropriate returns on equity, the deletion of the proposed decision's discussion of appropriate utility bond ratings, and the decision to increase SDG&E's equity ratio. I believe that the adopted ROEs are excessive and that the decision's departures from traditional cost of capital analysis are unfortunate and inappropriate.

First, I take issue with the adopted returns on equity (ROE). The administrative law judge's proposed decision contained ROEs significantly higher than DRA's recommended range of ROEs, and higher than those suggested by the drop in interest and bond rates

since our last cost of capital decision. Today's decision, which adds 20 basis points to the ALJ's recommendations, yields excessive ROEs which are not just and reasonable given the facts before us at this time.

Merrill Lynch's Quarterly Regulatory Report for October, 1989 shows that ROEs for electric utilities have trended downward from 12.90% in the first quarter of 1989 to 12.25% in the 3rd quarter. Gas utility ROEs have trended downward from 12.62% to 12.54% The Federal Energy Regulatory Commission (FERC) set its most recent quarterly benchmark return on equity for electric utilities at 12.04%, a significant decline from the prior quarter (12.43%). A year ago, AA utility bonds yielded approximately 9%. Today, the yield is approximately 8%. In the past, the returns we have authorized for California energy utilities have approximated the returns granted nationwide. With today's authorization of ROEs ranging from 12.85% to 13.05%, we have stepped far outside the mainstream.

I feel that the Commission's decision to increase the ALJ's proposed ROEs by 20 basis points was both unwise and unwarranted. Although the magnitude of these adjustment may at first seem small, the total result is an increase in the revenue requirement of Southern California Edision, Pacific Gas and Electric, Southern California Gas, and San Diego Gas and Electric of $39 million dollars. Although utility shareholders certainly have something extra to be thankful for this holiday season, ratepayers do not. From the ratepayers' perspective, today's decision lacks the fair and careful balancing of interests which we strive to achieve.

Second, I believe the ALJ properly analyzed bond rating benefits when he concluded that capital structures which support bond ratings no greater than single A are adequate. By deleting this section of his proposed decision, the Commission encourages utilities to seek capital structures characteristic of higher bond ratings. Such capital structures, with their high equity

components, may be excessively costly to ratepayers since equity generally costs more than debt.

Third, I think that the decision reflects a misunderstanding of the impact of capital leases on SDG&E's cost of capital and that this misunderstanding leads to an inappropriate increase in SDG&E's equity ratio. After a brief reference to the history of SDG&E's capital leasing program, I will point out why today's decision is wrong.

SDG&E entered into the capital leasing arrangements it now praises out of necessity rather than choice. At the time these leases commenced, SDG&E was in dire financial straits and was for all practical purposes unable to raise capital through the issuance of debt or equity. Investors quite naturally shied away from this high risk utility. By selling and leasing back its headquarters building and its Encina 5 generating plant, SDG&E was able to recover the debt and equity capital it had invested in these facilities and thus avoid the need to issue new debt or equity for future capital projects. This result of the leasing arrangements points out why SDG&E's long term capital leases are treated as an operational expense and not given rate base treatment. While the capital leases do indeed cover capital assets, they are not included in SDG&E's rate base since they do not represent a ratemaking debt or equity investment by utility shareholders. The leases, in essence, take the place of rate base investments for which the utility would otherwise obtain an appropriate rate of return.

Naturally, rate base rate of return compensation is not appropriate for items which are not in rate base. Double counting results if capital structure adjustments are made as if the capital leases were in rate base, and the utility is granted a return on equity based on such an adjustment, when in fact the utility is already compensated for the capital lease payments through its operating expenses.

In this proceeding, SDG&E asks us to look at its "total financial capital structure," which includes all long term capitalization whether in rate base or not, when determining an appropriate rate base equity ratio. SDG&E argues that the use of traditional rate base capital ratios is unfair in its case because a significant portion of its capitalized assets are financed through long term capital lease arrangements rather than through rate base investment. SDG&E's rate base equity ratio appears high, the utility contends, because non-rate base capital leases which are a long term obligation equivalent to debt are excluded from the capital structure upon which the rate base equity ratio is based. SDG&E claims that if its equity ratio is computed on the basis of an overall capital asset pie containing rate base debt, rate base preferred stock, rate base equity and non-rate base capital leases, then the financial equity ratio it proposes appears smaller than the 49.5% rate base equity ratio it seeks, and appears more in line with the equivalent equity ratios of other utilities. SDG&E apparently concludes that the appearance of an equity ratio reduction which results from the use of an overall financial equity ratio requires an offsetting increase in the rate base equity ratio if the utility is to be given an opportunity to earn its authorized return on all its outstanding equity.

In accepting SDG&E's position, the decision states that SDG&E's use of capital leases has been of benefit to ratepayers, and that DRA's recommendation of a 48% equity ratio, the same equity ratio we found reasonable for SDG&E's 1989 attrition year, could discourage further use of long term leases. The decision appears to imply that DRA's proposed rate base equity ratio would somehow penalize SDG&E for the use of lease financing by excluding such financing from its rate base cost of capital analysis.

When analyzing the impact of a switch from rate base capital structures to overall financial capital structures it is important to keep in mind the fact that if non-rate base debt equivalent

capital assets (i.e., long term capital leases) are added to rate base assets the overall capital asset pie becomes bigger and the portion of that pie which is represented by equity inevitably becomes smaller. This shrinking equity ratio is nothing to be alarmed at, since it does not mean shareholders earn a return on a lesser amount of actual equity dollars, but simply that the dollars of equity represent a smaller piece of the total asset pie. One may reasonably compare the resulting "financial equity ratios" of one utility with another, but only as long as one does so on an "apples to apples" basis. Obviously, a "financial equity ratio" is not directly comparable to a "rate base equity ratio."

While SDG&E is correct insofar as its proposed financial equity ratio is smaller than its proposed rate base equity ratio, this does not suggest that a 49.5% rate base equity ratio is appropriate. The smaller financial equity ratio results in no hardship to shareholders, who receive a return on rate base debt and equity assets and receive operating expenses to cover non-rate base long term capital lease costs. Even when capital leases are taken into account and a "financial capital structure" determined, the equity component of that financial capital structure is according to SDG&E's own testimony still 120 to 270 basis points higher than the equivalent equity ratios of Pacific Gas and Electric and Southern California Edison.

The decision implies that DRA's recommendation penalizes SDG&E for entering into long term leases by excluding such leases from the capital structure from which SDG&E's rate base equity ratio is determined. This is not the case. DRA simply makes the point that only rate base assets should be used in determining rate base equity ratios, and that SDG&E's proposed 49.5% rate base equity ratio is excessive when compared to the rate base equity ratios of other utilities.

The decision also misstates the theoretical benefits of capital leases. While it is true that the use of capital leases

might in some cases afford ratepayers a capital asset at less expense than would be the case if the utility had invested its own capital in constructing that asset, this is the case only where the cost of the long term lease is over its lifetime less than the return ratepayers would pay the utility if the utility itself had constructed and maintained the asset. Since the return paid by ratepayers decreases as an asset is depreciated, one cannot blithely assume that capital leases will always be a good deal for ratepayers.

Even if capital leases were always a benefit to ratepayers, the decision errs in concluding that higher equity ratios provide incentives for utilities to pursue long term leasing arrangements. Given a choice, what utility would opt for a lease arrangement and forego rate base rate of return treatment of a capital investment? In our experience, utilities have requested leasing arrangements only in the most extreme financial circumstances.

Next, I ask why SDG&E should now prevail with a shopworn capital leasing argument rejected by two Commission decisions within the last year. This issue was fully discussed and resolved in the 1989 attrition case, D.88-12-094, wherein the Commission determined that a reasonable equity ratio for SDG&E was 48%. The Commission affirmed its position in D.89-04-051, dated April 12, 1989 in its denial of SDG&E's petition to modify the equity ratio found reasonable in D.88-12-094. Today's decision contains no compelling arguments justifying an upward adjustment in SDG&E's equity ratio. I believe that the ALJ's decision which rejected SDG&E's position was correct.

Finally, even if it were appropriate to increase SDG&E's rate base equity ratio for some reason other than to reflect capital leases, it would not be appropriate to at the same time increase the utility's return on equity. One of the most basic assumptions of ratemaking economics is that a utility's financial riskiness decreases as its equity ratio increases. This is one

reason why bond rating agencies tend to give higher ratings to utilities with more equity in their capital structure. The yield of higher rated bonds tends to be lower than the yields of lower rated bonds precisely because they are considered less risky; the less the risk, the less the yield demanded by prospective investors. By increasing SDG&E's equity ratio, albeit on the erroneous assumption that to do so properly reflects the use of capital leases, the Commission has actually reduced SDG&E's financial risk. This reduction should be accompanied by a decrease, rather than an increase, in ROE. Today's decision goes 180 degrees the wrong way, all to the detriment of ratepayers.

The Commission's decision D.89-04-051, issued just seven months ago, properly notes the relationship between equity ratio, financial risk, and appropriate return on equity. Adopting a 48% equity ratio instead of the 51% ratio proposed by the utility, the Commission noted:

> "If the proposed common equity ratio of 51% were adopted, a corresponding downward adjustment of the reurn on common equity would be required. Return on equity is a function of risk. The higher the risk, the greater the return on equity." (D.89-04-051, Slip Opinion, p. 3)

I believe the Commission should on its own motion rehear these matters and make appropriate adjustments as discussed herein.

Frederick R. Duda, Commissioner

November 22, 1989
San Francisco, California

JOHN B. OHANIAN, Commissioner, Concurring:

Although I have problems with this decision, I concur with the majority because my crystal ball is no better than the assigned Commissioner's crystal ball.

I am troubled by the comparison with returns on equity granted in other states. The record shows that such returns average about 13% elsewhere, but that figure is for the fiscal year 1988-1989, which does not reflect today's improved financial conditions. The utilities respond that improvements in financial markets have been offset by increased risk, but that claim conflicts with recent completion of major prudency reviews, stable fuel prices, high market-to-book ratios and solid earnings.

However, I am more concerned about the Commission's process in authorizing return on equity than about particular problems with this decision. Comparisons with other states are overly general. This Commission has authorized many ratemaking mechanisms which reduce utility risk and which are not available in all other states. Examples are attrition, the Electric Revenue Adjustment Mechanism (ERAM) and fuel cost balancing accounts.

I am also dissatisfied with the vagueness in our balancing of risks, rewards and interest rate trends. What is the proper weighting of those major elements? Our analysis of utility risks should be more specific and more rigorous if possible. Risk is very real, but it is the risk of specific harmful outcomes that we should consider, not vague claims of regulatory "climate" or financial "uncertainty."

Some of my concerns are probably frustrations with forecast test year ratemaking. We are stuck with the agony of forecasting the future. At the same time, I would ask my colleagues if it isn't time to take another look at how we regulate energy utilities. We have introduced incentive or performance based regulation into certain industries (e.g. recent efforts for the major telephone utilities, and the Diablo Canyon nuclear plant settlement). Our electric industry investigation (I.86-10-001) has been closed, in my opinion due to lack of focus, but perhaps the need still exists to look at opportunities for a better process. Possibilities include incentive regulation, reassessment of utility risks, annual rate cases, and others. We can do better.

John B. Ohanian, Commissioner

November 22, 1989
San Francisco, California

I N D E X

While oversight of utility capitalization is necessary and appropriate, we believe utilities must be given some discretion to manage their capitalization with a view towards not only shareholder interests but also regulatory requirements and ratepayers' interests. Establishing ranges around the fixed targets might appear to allow such managerial discretion, but we believe that such an approach could aggravate the problem by creating the presumption that any capital structure consistent with the allowable ranges is reasonable when that might not be the case. We conclude that regulation to ensure that utilities are managing their capitalization to optimal levels will be most effective if it is on a case-by-case basis and if it allows for consideration of variations over time and among utilities.

It should be emphasized that we are not excusing utilities from their burden of showing that their capital structures and their ratemaking capital structure proposals are reasonable and justified in cost of capital proceedings. We anticipate that capital structure issues will continue to be important parts of these proceedings, particularly the question whether equity-rich structures should be adopted.

DRA's recommendation that issuance of preferred stock be considered an acceptable financing alternative has merit. Although we are not adopting DRA's target recommendation of 10% preferred stock, we will give careful consideration to the utilities' use of preferred stock and make adjustments to authorized capital structures if they are not making appropriate use of this financing alternative.

In weighing the arguments concerning SDG&E's capital ratio, we find the balance tipped in favor of SDG&E's position. The evidence is uncontroverted that SDG&E's use of long-term leases has been of benefit to ratepayers. The use of such leases can provide a valuable, low-cost financing option and SDG&E's decision to follow this route demonstrates this fact.

DRA's proposal to adjust SDG&E's equity ratio is predicated on the intricacies of ratemaking rather than any compelling policy. We reflect the costs of lease financing as an operating cost and not a capital cost, notwithstanding the true "capital" nature of those costs. To then say that SDG&E's capital structure, purged of lease financing, is too equity laden is to penalize SDG&E for our ratemaking practice. Taken as a whole, SDG&E's financial planning appears to be reasonable; DRA even cites SDG&E's strong financial performance and rating in its arguments concerning return of equity. We also believe that DRA's position could discourage further use of long-term leases despite their benefits. We specifically reject DRA's assertion that inclusion of lease financing in evaluating SDG&E's capital structure will result in double counting of financing costs.

We conclude from all of the above that SDG&E's proposed equity ratio of 49.50% is reasonable and should be adopted. We will adopt a capital structure of 44.25% long-term debt, 6.25% preferred stock and 49.50% common equity.

C. Cost of Long-Term Debt and Preferred Stock

As shown in late-filed Exhibit 40, SDG&E and DRA disagree on the estimated cost of embedded debt for 1990. SDG&E's 9.13% estimate is based on its forecast of a 10% yield on AA utility bonds in 1990 and its 35 basis point additive to reflect it lower

and reasonable for SDG&E in 1990. While this return is at or above the upper limit of the financial model results, except SDG&E's RPM analysis, it gives recognition to the overall level of business and financial risk facing SDG&E, including our adopted capital structure. We are also recognizing that the overall levels of inflation and interest rates appear to be more favorable than when we established SDG&E's return for 1989 one year ago, but at the same time there is some uncertainty and volatility in financial markets.

E. Adopted Cost of Capital

The 12.90% adopted return on common equity produces an overall rate of return of 10.86% for 1990, as shown in the following table depicting the adopted cost of capital:

SDG&E's Adopted Cost of Capital

Component	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	44.25%	9.08%	4.02%
Preferred Stock	6.25	7.18	0.45
Common Equity	49.50	12.90	6.39
TOTAL	100.00%		10.86%

F. Implementation

SDG&E proposes to implement the cost of capital authorized in this proceeding in conjunction with its 1990 operational attrition advice letter filing. The proposed rate changes submitted with the application were developed using the currently adopted rate design and revenue allocation procedures. SDG&E notes that the proposed electric rates incorporate a sales forecast which is consistent with the forecast filed with A.88-12-035 (for authority to merge SDG&E and Edison), but which is higher than the currently adopted electric sales forecast. SDG&E states that it has no objection to deferring the electric rate changes to coincide with the next electric rate change scheduled for May 1, 1990 under the Energy Cost Adjustment Clause (ECAC).

model results calculated by the parties. We conclude on the basis of this record that such an additive is not justified for 1990. The record shows that SPPC has not issued stock since 1984, nor does it disclose that SPPC plans to do so in 1990.

Since the proposed capital structure is not significantly different from the currently adopted structure, DRA believes that the level of financial risk facing SPPC has not changed significantly since the cost of capital was last reviewed for 1989. DRA does recommend that SPPC's return on equity be set higher than the return for the other electric utilities in recognition of greater relative risk. DRA notes that SPPC is more leveraged than the other electric utilities, and that on the basis of 1988 revenues, SPPC is the smallest of the utilities analyzed, with approximately $408 million in revenues compared to an average of $2.9 billion for the electric utility group and an average of $5.3 billion for the California electric utilities.

After considering all the evidence of the market conditions, trends, and the quantitative models presented by the parties, we conclude that a 13.00% return on common equity is just and reasonable for SPPC in 1990. In doing so, we are recognizing that the overall levels of inflation and interest rates appear to more favorable than when we established SPPC's return for 1989 one year ago, but at the same time there is some uncertainty and volatility in financial markets. By setting a return on equity which is higher than the return generally indicated by the results of the financial models, we are also recognizing SPPC's relative risk compared to the other electric utilities.

E. Adopted Cost of Capital

The 13.00% adopted return on common equity produces an overall rate of return of 10.34% for 1990, as shown in the following table depicting the adopted cost of capital: