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ORIGINAL

Decision No. 80430

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of SOUTHERN CALIFORNIA GAS COMPANY for (a) A General Increase in Its Gas Rates, (b) For Authority Either to Include a Purchased Gas Adjustment Provision in Its Tariffs or to Implement an Enlarged Advice Letter Procedure for Reflecting in Its Rates Changes In Purchased Gas Costs; (c) For Authority to Modify the Service Agreements Under Schedules G-58, G-58A and G-61; and (d) For Authority to Consolidate and Otherwise Modify Certain of Its Tariff Schedules.	Application No. 52696 (Filed June 18, 1971)

(List of Appearances in Appendix A)

O P I N I O N

By the above-entitled application, Southern California Gas Company (SoCal) seeks authority for a general increase in its gas rates above existing rates by $64,243,000 annually. This requested increase in gross revenues is based upon its summary of earnings for test year 1972 appended as Exhibit G to the application. However, during the course of hearings, certain changes were made by applicant in its estimated operational results which have the effect of lowering the additional revenue requirement sponsored by applicant to approximately $58.7 million. A rate of return of 8.5 percent is being sought which compares with the 7.75 percent rate of return upon which rates were set in SoCal's last general rate proceeding based on a 1970 test year.

In this application SoCal also requests:

(1) Authority to incorporate in its tariff schedules a purchased gas adjustment provision or, in the alternative, to adjust its rates by an expanded Advice Letter Procedure to offset any change in the cost of purchased gas attributable to changes in the rates charged to SoCal by its suppliers.

(2) Authority to consolidate and otherwise modify its tariff schedules.

(3) The Commission to exercise its continuing jurisdiction over certain service agreements and pursuant to that jurisdiction order certain modifications of the service agreements under Schedules G-58, G-58A and G-61.

In Application No. 52445, an earlier application consolidated for further hearing with Application No. 52696, SoCal seeks authority to include in its tariff schedules a provision to relate charges for firm general service to deviations of recorded temperatures from average temperatures. Our decision concerning Application No. 52445 is being issued concurrently.

Public Hearing

After due notice, hearings on Application No. 52696 and further hearings on Application No. 52445 began on October 27, 1971. A total of 31 days of public hearings were held in Los Angeles before Commissioner Sturgeon and Examiner Main over a period extending through February 28, 1972, during which time all parties and the general public were given an opportunity to present testimony and evidence.

SoCal and its affiliate, Pacific Lighting Service Company (PLS Co), through witnesses, presented testimony and exhibits in support of its requests. The Commission's staff presented its evaluation of such requests through a comprehensive direct case. In addition, parties to the proceeding who sponsored evidence or participated in cross-examination include: San Diego Gas & Electric Company (SDG&E), Southern California Edison Company (SCE), City of Los Angeles, Imperial Irrigation District, California Manufacturers Association (CMA), General Services Administration (GSA), and cities of Burbank, Glendale and Pasadena.

On February 28, 1972, these matters were submitted for decision subject to the filing of Exhibit 81 on or before March 8, 1972, opening briefs on April 5, 1972 and reply briefs on April 20, 1972.

Applicant's Position

Applicant states that it has sustained many cost increases not reflected in rates set in its last general rate proceeding (Decisions Nos. 77975 and 77976 dated November 24, 1970 in Applications Nos. 51567 and 51568), significant increases having been experienced in wages, employee benefits and other costs of doing business as a result of continuing pressure of inflation. Applicant contends that without an increase in rates to incorporate such increase in costs, its earnings would decline to a level where corporate credit would be impaired, the quality of service to the public would be threatened, and the investors in its securities would be irreparably damaged.

Inasmuch as applicant's costs are directly affected by its closely affiliated inter-relation with PLS Co, the operations and costs of doing business of that company form a part of SoCal's basic showing in this application. To protect the financial integrity of applicant and its affiliate, PLS Co, hereinafter sometimes referred to as the Pacific Lighting Utility System (PLU System), applicant represents that an 8.50 percent rate of return on the PLU System rate base is needed.

Applicant further contends that additional authority to offset gas cost changes is necessary in order to protect the PLU System from adverse economic impact associated with the rapid and significant changes in purchased gas costs applicant estimates will occur in the future. This aspect of the relief sought by the applicant can be accomplished either by the implementation of a purchased gas adjustment provision in applicant's tariff or by an enlargement of its present Advice Letter Procedure.

Applicant states that its contracts under Schedules G-58 and G-58A should be clarified with respect to their provisions for deliveries of specific quantities to these customers consistent with applicant's actual ability to deliver gas under supply shortage conditions. Applicant also states that its contract under Schedule G-61 should be modified so as to bring the level of service to SDG&E electric generation plants closely in line with the level of service provided to its utility retail electric plant customers served under its Schedule G-58.

Finally, it is applicant's further position that it is necessary to consolidate and otherwise modify certain of its tariff schedules if it is to comply with the Commission's directive in Decision No. 77010 authorizing the merger of Southern Counties Gas Company of California (So Counties) into SoCal.

Gas Supply Shortage

Since we issued our decision in SoCal's last general rate case near the end of 1970, there has been a clear emergence of a national gas supply shortage. This gas supply shortage, although it is more severe in other parts of the country, is having a significant impact in Southern California. In turn, the gas supply shortage affects the facts and issues in this proceeding.

During most of the past decade the PLU System has been able to contract for increments of gas from out-of-state sources as needed. The out-of-state suppliers have been able to obtain adequate gas reserves to support the certification of such increments by the Federal Power Commission. During most of this same time period, California gas supplies available to the PLU System remained at a relatively high level. Since 1969, the situation has changed. New contracts or certificates have not been obtained and the last new out-of-state increment under contract was received by SoCal in late 1971. The availability of California gas has declined drastically.

As the result, a number of things have happened which are reflected in this case. First, with this decline in supply there is a corresponding decrease in level of service to interruptible customers. To date the great impact of the decline of level of service has been upon the utility electric generation customers. In addition, along with the decrease of supply there has been an increase in the cost of alternate fuels for the interruptible customers. There also has developed an imbalance in the level of service to the utility electric generation plants served at retail and by a wholesale customer (SDG&E) of SoCal.

Without new increments of gas it is now necessary to find other means of preparing to meet the needs of firm customers under peak conditions along with other means of meeting seasonal load equation. It also has become necessary for the PLU System to participate in gas development activities to seek to meet the needs of customers in the future. As the result, there are a greater number of issues in this proceeding than in the usual major rate case.

For convenience the issues raised in this proceeding will be discussed under subjects designated in center headings having the following sequence:

A - Rate of Return

B - Results of Operation

C - Rate Spread

D - Parity Proposals and Curtailment Priority System

E - Proposed G-58 Contract Revisions, Proposed Conversion of Schedule G-61 to Therm Rates, and Contingent Offset Charges

F - Proposed Purchased Gas Adjustment Clause

A - Rate of Return

A public utility is constitutionally entitled to an opportunity to earn a reasonable return on its investment which is lawfully devoted to the public use. Within this context, a fair and reasonable rate of return applied to an appropriately derived rate base quantifies the earnings opportunity available to the utility after recovery of operating expenses, depreciation allowances and taxes. In a similar vein, the return or earnings on invested capital provide for the interest payable by the company on its debt, dividends on preferred stock, and earnings on common equity.

Ultimately, the rate of return determination in this proceeding must represent the exercise of informed and impartial judgment by the Commission, which must necessarily give equal weight to customer and investor interests in deciding what constitutes a fair and reasonable rate of return. Such balancing of interests is directed toward providing customers with the lowest rates practicable, consistent with the protection of the utility's capacity to function and progress in furnishing the public with satisfactory, efficient service and to maintain its financial integrity, attract capital on reasonable terms and compensate its stockholders appropriately for the use of their money. After considering all of the evidence, the Commission concludes that a rate of return of 8.0 percent is fair and reasonable for applicant and its utility affiliate, Pacific Lighting Service Company, comprising together the so-called Pacific Lighting Utility System (PLU System).

We will proceed now to a consideration of the evidence which assisted us in arriving at the rate of return we judge to be fair and reasonable.

Testimony and exhibits concerning the fair rate of return for PLU System were presented by Witness Jensen for applicant, who recommends an 8.5 percent rate of return, Witness Scheibe of the Commission's staff, who recommends a rate of return in a range of 7.65 to 7.95 percent, and Witness Kroman of the City of Los Angeles, who recommends a rate of return of 7.75 percent. In addition, applicant contends that if its earnings stabilization rate proposal (Application No. 52445) is not approved, a higher rate of return than 8.5 percent is warranted. But, conversely, the City of Los Angeles contends that a rate of return of not more than 7.5 percent would be appropriate if that rate proposal is approved. The staff's rate of return witness takes the position that whatever action is taken in this regard would be accommodated within his recommended range of 7.65 to 7.95 percent.

In their respective studies, the witnesses used different capital ratios for the PLU System. Applicant's witness presented two sets of year-end 1972 capital ratios, one as estimated and the other as adjusted to limit the debt ratio to 50 percent. The staff witness developed similar estimated year-end 1972 capital ratios. The witness for the City of Los Angeles used the year-end 1970 capital ratios adopted in Decision No. 77975. In the capital ratios employed by applicant and by the City of Los Angeles, all of the preferred stock of the parent corporation, Pacific Lighting Corporation, is imputed to the capital structure of the PLU System. The staff witness attributed approximately 80 percent of the preferred stock of the parent to the PLU System. In tabular form the capital ratios used in the several studies are:

Pacific Lighting Utility System

Capital Ratios

	Year End 1972			Year End 1970
	Applicant		Staff	L.A. City
	Estimated	Adjusted*	Estimated	(D-77975 Basis)
	%	%	%	%
Long-term Debt	46.2	46.2	46.-	45.6
Short-term Debt	6.8	3.8	8.-	4.4
Subtotal	53.0	50.0	54.-	50.0
Preferred Stock	10.7	10.7	9.-	12.0
Common Equity	36.3	39.3	37.-	38.0
Total	100.0	100.0	100.-	100.0

* Adjusted to limit debt to 50 percent, replacing short-term debt financing in part by common equity.

Witness Jensen for applicant provides data in Table 21 of Exhibit 4 to calculate the earnings rate which would flow to common stock equity for the PLU System at his recommended 8.5 percent rate of return. Based on year-end 1972 estimated cost rates of 5.86 percent for long-term debt, 6.00 percent for short-term debt, and 4.83 percent for preferred stock, the resultant earnings on common equity is 13.39 percent with 53.0 percent debt and 36.3 percent common equity in the capital structure. This decreases to a 12.82 percent return on common equity when debt is limited to 50 percent and the common stock equity ratio increased to 39.3 percent as set forth above in the adjusted capital structure. Under this adjusted capital structure times interest earned (fixed charges times earned)[1/] increases to 2.89 from the 2.72 which results under the estimated (unadjusted) year-end 1972 capital structure.

1/ Unless otherwise specified, coverage ratios set forth in this decision are after taxes.

In arriving at his rate of return recommendation, this witness considered many factors such as system's size, capital structure, costs of capital, growth potential, requirements for capital, interest coverage, effects of past inflation, regulatory lag, competition, comparative risks, economic conditions, and revenue mix, as well as special factors concerning risks of the system including the critical problem of obtaining additional gas supplies and the deterioration of heating value of its gas supplies.

As an important support for this recommendation, the witness relies upon the test of earnings comparability. The comparative capital, earnings, and interest coverage ratios for his selected groups of companies and the PLU System are summarized:

1965-1969 Average	10 Straight Electric	5 Largest Natural Gas Distributors	Pacific Lighting Utility System*
CAPITAL RATIOS - Percent			
Debt	52.0	51.3	44.3
Preferred Stock	7.9	1.3	13.1
Common Stock	40.1	47.4	42.6
EARNINGS RATIOS - Percent			
Debt	4.15	4.50	4.41
Preferred Stock	4.54	4.76	4.84
Common Stock	13.53	13.91	10.34
Total Capital	7.99	8.88	6.99
Interest Coverage			
Times Interest Earned	3.87	4.02	3.62
Times Interest Earned (1970)	2.72	3.02	

*Attributing Pacific Lighting Corporation preferred stock to the utility system.

The rate of return witness for the staff does not rely primarily on the comparable earnings approach but uses it as a guide. For this purpose he used ten of the largest gas companies and ten of the largest combination gas and electric companies.

His recommended range in rate of return from 7.65 percent to 7.95 percent reflects his judgment as to the needs and circumstances of the PLU System. Based on year-end 1972 estimated cost rates of 5.82 percent for long-term debt, 5.50 percent for short-term debt, and 4.83 percent for preferred stock, his recommendation provides a range of return on common equity from 11.05 to 11.86 percent with the 37 percent common equity in the capital structure which he used.

The witness for the City of Los Angeles recommended a rate of return of 7.75 percent, based primarily on an updating of the 7.75 percent rate of return upon which rates were set in Decision No. 77975. His recommendation equates to an11.16 percent return on common equity under capital ratios adopted in Decision No. 77975 but with cost factors of 5.86 percent for long-term debt, 6.00 percent for short-term debt, and 4.83 percent for preferred stock. Such an allowance on equity represents in his judgment a fair and reasonable amount based upon several analyses and considerations, including (1) changes in earnings in common equity of other groups of utilities; (2) returns on equity recently allowed by the Commission for other major utilities; (3) relative magnitude of prospective external financing and rate of growth in utility plant; (4) interest coverage trends; (5) gains realized from reacquired bonds; and (6) similarity of risks with those advanced in the 1970 proceedings which led to Decision No. 77975.

The principal presentations on rate of return and the critiques in the record have been of assistance to the Commission in making an informed and impartial judgment determination of the fair rate of return of 8.0 percent for the PLU System. It appears desirable, however, to examine the rate of return of 8.0 percent in light of certain criteria and special circumstances set forth in paragraph (d) of Section 300.16 of the Price Commission's regulations, 37 Federal Register, pp. 5701 and 5702. Within said paragraph (d), subparagraph (3)(iv) taken in conjunction with subparagraph (3)(v) provides the following specific criteria and special circumstance which bear upon a rate of return allowable by the Price Commission and, in turn, corroborate the level of rate of return we judge to be fair and reasonable.

> "(3)(iv) The projected rate of return on common equity capital, after the price increase has gone into effect, will be no more than the projected rate of return on common equity capital which was granted to the utility by the last decision of the regulatory agency applicable to that utility . . .
>
> "(3)(v)(a) The past and current ratios of the utility's debt capital to the sum of its debt and equity capital and of the utility's fixed charges to its earnings available to pay those charges."

In Decision No. 77975 dated November 24, 1970 in Application No. 51567, we found a reasonable range of rate of return for the PLU System to be 7.65 to 7.85 percent. Such a range of return, when considered with the then cost of debt money of 5.46 percent and preferred stock money of 4.83 percent, was calculated to produce returns on common stock equity attributable to PLU System of 11.42 percent to 11.95 percent, based on a capital structure of 50 percent debt, 12 percent preferred stock, and 38 percent common equity. Rates for gas service were set in Decision No. 77975 to yield a 7.75 percent rate of return.

A comparative summary of the rate of earnings on capital, as derived from Decision No. 77975 for test year 1970 and as adopted herein for test year 1972, follows:

Pacific Lighting Utility System
Rate of Earnings on Capital

Item	Test Year 1970 Capital Ratios	Test Year 1970 Cost Rates	Test Year 1970 Return Component	Test Year 1972 Capital Ratios	Test Year 1972 Cost Rates	Test Year 1972 Return Component
Debt	50.0	5.46	2.73	50.0*	5.80*	2.90
Preferred Stock	12.0	4.83	.58	10.7	4.83	.52
Common Equity	38.0	11.68	4.44	39.3	11.65	4.58
Total	100.0		7.75	100.0		8.00
Times Interest Earned**			2.84			2.76

* Breakdown:	Long-Term Debt	Short-Term Debt
Capital Ratios	46.2	3.8
Cost Rates	5.82	5.50

** Applicant's mortgage bonds are Aa-rated; PLS Co's debt securities (debentures) are A-rated.

Before leaving this very important element of the rate-making process, we would observe that the rate of return of 8.0 percent for PLU System falls within the range of returns upon which rates were set in the recent general rate proceedings of General Telephone Company of California, Southern California Edison Company and The Pacific Telephone & Telegraph Company. In Decision No. 79367 dated November 22, 1971, rates for General were set on an 8.3 percent rate of return to yield common equity earnings of 11.3 percent and approximate interest coverage of 2.4. General's related common equity ratio is 41 percent and its mortgage bonds are A-rated. Rates for Edison were set in Decision No. 78802 dated June 15, 1971, to yield a 7.9 percent rate of return. At this level Edison's return on common equity with a 37 percent common equity ratio is about 11.9 percent and the interest coverage for its Aa-rated debt securities is 2.9. In Decision No. 78851 dated June 22, 1971, rates for Pacific were set on a 7.85 percent rate of return to yield common equity earnings of 9.5 percent and approximate interest coverage of 3.1. Pacific's equity ratio is about 56 percent and its debt securities carry an "Aaa" rating.

From these ultimate results, we would further observe that the computed rates of return of PLU System, General, Edison, and Pacific, while not, of course, directly comparable any more than the companies themselves, are within the scope of a rational pattern, one which reflects an inverse relationship of return on common equity with equity ratio, on the one hand, and of interest coverages moving in the direction of security ratings, on the other. Similarly, there is reasonable consistency in the consumer burden, as indicated by the combined effect of return and income taxes, imposed by the several levels of rate of return. And finally, in this context gas utilities are less capital intensive than electric or telephone utilities but have potential for larger swings in earnings and, therefore, less earnings stability because of climatic results as between years. The fair rate of return of 8.0 percent for PLU System encompasses all relevant considerations including such differences.

B - Results of Operation

Both applicant and the staff of the Commission presented results of operation of SoCal and of PLS Co for test year 1972. Within this test year all elements of productivity for revenues, including increasing firm sales and declining interruptible sales in the revenue "mix", customer growth and efficiencies of size in operating expenses and facilities are reflected automatically, such elements being inherent to the process used to develop the estimated operational results.

During the course of the proceeding, a number of important revisions were made by the applicant and the staff in their respective estimates of revenues, expenses, net revenues, and rate base for each company. Among others, such revisions include applicant's adopting certain staff adjustments for the purpose of expediting the proceeding; the staff's reflecting the current 7.6 percent rate for the California corporation and franchise tax and revised calculations concerning the investment tax credit and the asset depreciation range; and both applicant's and the staff's eliminating the PG&E source gas[2/] and reflecting an expanded gas development program in the test year 1972 results. Their final test year 1972 results are set forth in Exhibits 79 and 81.

Operational results of SoCal will be taken up now and those of PLS Co will be set out at a later point. In Table 1 below the comparative results of SoCal's operation for test year 1972, as set forth in Exhibits 79 and 81, are summarized and the operating results we adopt for test year 1972 under "Present Rates" are shown. "Present Rates" are those which were on file and effective in applicant's tariffs other than for resale as of April 9, 1971 and exclude all tracking increases which have occurred since that date.

2/ The PG&E source gas is available only under a special one-year contract and is being sold under special contracts approved by the Commission to certain utility electric generation customers outside the regular tariff schedules. The costs of this gas substantially offset the revenues, resulting in a minimal rate of return impact of about .01 percent.

TABLE 1

SOUTHERN CALIFORNIA GAS COMPANY

Results of Operation Under
"Present Rates" - Test Year 1972

Item	Staff	Utility	Utility Exceeds Staff	Adopted
		(Dollars in Thousands)		
Operating Revenues	$691,699	$687,844	$(3,855)	$690,442
Operation and Maintenance Expenses				
Production	415,063	420,029	4,966	415,347
Storage	1,348	1,484	136	1,385
Transmission	7,000	7,221	221	7,162
Distribution	52,830	55,985	3,155	55,031
Customer Accounts	27,471	28,658	1,187	28,306
Sales	10,000	15,641	5,641	12,600
Admin. & General	49,305	52,682	3,377	51,405
Total O & M Expenses	563,017	581,700	18,683	571,236
Taxes				
Taxes Other Than Income	24,223	26,330	2,107	24,244
Federal Income	15,102	7,870	(7,232)	10,910
State Income	2,933	1,241	(1,692)	2,307
Total Taxes	42,258	35,441	(6,817)	37,461
Depreciation	31,032	31,032	-	31,032
Total Oper. Expenses	636,307	648,173	11,866	639,729
Affiliated Interest Adjustment	78	78	-	78
Return	55,470	39,749	(15,721)	50,791
Rate Base				
Working Cash	3,971	17,200	13,229	8,952
Remainder	761,725	761,725	-	761,725
Total Rate Base	$765,696	$778,925	$13,229	$770,677
Rate of Return	7.24%	5.10%	(2.14)%	6.59%

(Inverse Item)

Operating Revenues

The staff's estimate of operating revenues exceeds applicant's estimate by $3,855,000, or by about one-half of one percent, largely as the result of differences between their estimates of (1) gas use per firm service meter, (2) deliveries to interruptible customers, and (3) number of customers taking optional residential service (Schedule No. G-10). About $2,500,000 of the total difference is attributable to the different estimates of customer requirements and the remaining $1,335,000 to effects of divergent estimates concerning the G-10 schedule.

With respect to the customer requirements, the staff's revenue estimate reflects higher firm deliveries based on an estimated use per meter of 139.8 Mcf, which exceeds the company estimate by 1.7 Mcf or by 1.2 percent. The difference in estimated use per meter is a result of the use of a 10-year trend by the staff and the use of a 20-year trend by the company. Other estimates by the company and staff of customer requirements were not significantly different, except the staff used later estimates of steam electric generating requirements for Southern California Edison Company and San Diego Gas & Electric Company and a different limitation and input in assigning priority to utility electric generation customers.

With limited gas supplies in the test year, the staff's higher estimate of firm sales yields lower interruptible sales than estimated by the company. In addition, the different limitation and input in assigning priority to electric generating customers results in a larger relative share of interruptible deliveries for those customers, producing a revenue shift as between classes of interruptible customers and a net reduction in revenue from such customer classes in comparison with the company's assignment of priorities. In essence, however, the $2,500,000 of the total difference in operating revenues is attributable primarily to the staff's higher estimated use per firm service customer and its corollary of lesser deliveries to interruptible customers.

Arguments advanced by SoCal in favor of using a 20-year trend or by the staff in favor of using a 10-year trend are not persuasive as to which trend period provides a more representative basis of projection of firm sales. Instead the arguments tend to confirm that either projection has resulted in an estimated use per firm service meter which lies within a reasonable range for use in the test year. We will avoid, however, using the upper end of this range in consideration of a possible decline in the system average heating value of gas from the 1061 Btu for 1972, as originally estimated by SoCal, to its revised estimate of 1057 Btu.

With respect to the remaining difference of $1,335,000, SoCal based the related portion of its revenue estimate upon 300,000 customers taking service on the G-10 schedule while the staff's revenue estimate reflects only 20,000 customers being so served. With the staff's estimating fewer customers being served on the G-10 schedule, but with the same total number of customers on firm service schedules as estimated by the company, higher total revenues result and the $1,335,000 difference can be viewed as representing the additional revenue generated by 280,000 customers being served on regular firm service schedules instead of on the optional G-10 schedule.

By way of background to this difference, Schedule No. G-10, as a lower cost option to residential customers with very small monthly use, provides for a lower initial block-charge and for higher unit charges for all usage in excess of two thermal units as compared to the other applicable general service schedules. It is a fairly recent schedule which did not become effective until early December 1970. As winter billing data became available shortly after the schedule was placedin effect, SoCal mailed informational inserts concerning this schedule with its bills to approximately 321,000 customers registering low gas usage during the months of January, February, or March 1971. The mailed material described the schedule and its advantages to very low usage customers. In addition, SoCal instructed its customer-contact employees to inform prospective customers applying for service to dwelling units with one bedroom or less of the optional schedule. A turnover rate of general service customers of approximately 30 percent per year gives some indication of the extent of this type of contact.

The response to the G-10 schedule has been quite limited, the record herein showing that by the end of April 1971, 14,795 customers had requested this service with the number of customers being served increasing to 15,764 by the end of May 1971, and dropping slightly to 15,758 by the end of August 1971. The record further shows that SoCal planned to repeat the procedure used last year for informational mailings, i.e., inserts were to be included with January, February, or March 1972 bills to small usage residential customers.

SoCal's estimate of 300,000 customers to be served on the G-10 schedule in test year 1972 assumes a further response to Schedule G-10 much greater than experience thus far appears to warrant. The staff's estimate of 20,000 customers is based on the response to this schedule during 1971 and on the expectation that informational mailings early this year would result in some additional customers.

Based upon this record, we find operating revenues of $690,442,000 at "Present Rates" to be reasonable for the test year 1972. This level of operating revenues is determinable by modifying the staff's estimates to reflect the effects of reducing the use per average firm service meter from 139.8 Mcf to 139.0 Mcf and the effects of increasing the number of customers accepting service on the G-10 schedule from 20,000 to 35,000 customers.

Operation and Maintenance Expenses

Applicant's estimate of $581,700,000 in total operation and maintenance expenses exceeds the staff's estimate of $563,017,000 by $18,683,000. This difference is shown in Table 2 of Exhibit 79 to result mainly from staff adjustments in five groupings as tabulated below:

	Staff Adjustments - M$				
Oper. & Maint. Expenses	PLS Co.	Wage Adjustment	Wage Differential	Basic Expense Est.	Employee Pensions-Benefits
Production	4,966				
Storage		50		86	
Transmission		221			
Distribution		3,002	153		
Cust. Accts.		1,149	59		
Sales		335	27	5,279	
Adm. & Gen.		1,696	63		1,667
Total Adj.	4,966	6,453	302	5,365	1,667

PLS Co Adjustment

Production expenses account for over 70 percent of applicant's total operation and maintenance expenses and consist mainly of costs of natural gas purchased from El Paso Natural Gas Company and from applicant's utility affiliate, PLS Co. Purchases from the latter company are made under a cost-of-service tariff, necessitating a determination of that company's results of operation for test year 1972 to determine in turn a substantial part of applicant's production expenses.

Applicant and staff agree upon all elements in the estimate of applicant's production expenses except PLS Co's total cost of operation, where applicant and staff are $4,966,000 apart excluding a $60,000 difference primarily in exchange revenues; thus, the staff adjustment of $4,966,000 for PLS Co constitutes the entire difference between their estimates of SoCal's production expenses of $420,029,000 and $415,063,000, the lower figure being the staff's estimate.

From our test year 1972 adopted operational results of PLS Co provided hereinafter in Table 2, the costs of operation which flow to SoCal under the cost-of-service tariff, which includes a fixed rate of return of 7.75 percent, amount to $171,201,000, which is $4,682,000 lower than estimated by applicant. We find reasonable and adopt production expenses of SoCal, with PLS Co at the existing 7.75 rate of return, in the amount of $415,347,000 for test year 1972 as shown in Table 1.

Wage Adjustments

Different test year 1972 wage levels were used. Applicant's estimates include a prospective wage increase of 7-1/2 percent for the test year 1972 over the wage level which was effective as of April 1, 1971. The staff's estimated expense levels are based on the April 1, 1971 wage levels with no allowance for any 1972 increase in wage levels. This treatment by the staff gives rise to the entry of $6,453,000 in the preceding tabulation of staff adjustments, which reflects a 7-1/2 percent wage increase on a full year basis.

In place of this 7-1/2 percent increase applicant and the unions, which represent most of applicant's employees, agreed upon an increase of 5-1/2 percent within the guidelines set by the Pay Board and the Price Commission. The 5-1/2 percent wage increase and related increase in employee benefits have been placed in effect as of April 1, 1972.3/

Annualization of this on-going level of increased wage expense is appropriate for rate-fixing purposes, especially in light of the incurrence of this expense prior to the effectiveness of the rate relief to be granted for the future in this proceeding. Accordingly, our adopted operating results for test year 1972 include an allowance in the sum of $3,549,000 plus $1,183,000 for the added wage expense with the latter figure being reflective of

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3/ The Pay Board approval (Decision and Order dated April 20, 1972 in Pay Board Case No. 00948) shows the increase as 4.9 percent. The difference between the 5.5 and 4.9 percent figures is the result of the Pay Board calculation method which measures the wage increase and related increase in employee benefits in relation to a larger base.

extending the effect of the wage increase from a nine months to a full year basis. This allowance can be equated to reducing either the staff's adjustment of $6,453,000 to $1,721,000 or applicant's expense estimates by $1,721,000. Its effect, broken down by expense categories, is thus to decrease applicant's estimates by the following amounts: Storage $13,000; Transmission $59,000; Distribution $801,000; Customer Accounts $306,000; Sales $90,000; and Administrative and General $452,000.

In addition to the inclusion of the 1972 wage increase, a further difference in the estimates of the applicant and the staff is over the inclusion of a wage differential adjustment in the amount of $302,000. The basis for the inclusion of this amount by applicant in its operations and maintenance expenses is explained in Exhibit 80 as follows:

> "The wage differentials are the result of the merger of the Southern Counties and the Southern California Gas Companies. The wage schedules of the two Companies, while similar, were not identical. The result, after the merger, was that in some job classification among represented employees, there were two different pay scales. The estimated total amount of the wage differential adjustment is $350,000, of which $302,000 applies to O&M accounts."

Notwithstanding an apparent need to eliminate different pay scales where they exist for the same job classification of applicant, this proposed elimination is not supported by a firm commitment to be carried out on a definite schedule. It is too speculative to be included in our adopted operating results for test year 1972.

Basic Expense Estimates

As shown in the tabulation hereinabove of staff adjustments, the staff's estimates are lower than those of applicant by $86,000 in storage expenses and by $5,279,000 in sales expenses as the result of basic differences in methods of estimating.

Applicant estimates storage expenses on an as-expected-to-be incurred basis, while the staff makes its estimates on a basis which is intended to have the effect of normalizing any extraordinary expenses. Our adopted storage expenses for test year 1972 reflect the $86,000 lower result of the staff's basic estimate.

Applicant's estimate of sales expenses was developed from forecasts of expenses by individual accounts. Its estimate of $15,641,000 exceeds the staff's estimate of $10,000,000 by $5,641,000 or 56 percent. A comparison of the two estimates for the test year with the actual sales expenses for the years 1970 and 1971 follows:

Ac. No.	Account	Year 1970	Year 1971	Test Year 1972 Applicant	Test Year 1972 Staff
911	Supervision	M$ 2,338	1,988	2,244	-
912	Demonst.& Selling	8,015	8,348	8,014	-
913	Advertising	4,371	4,048	4,026	-
914	Revenue from Merch.,etc.	(1,088)	(968)	(762)	-
915	Costs of Merch., etc.	1,115	972	762	-
916	Miscellaneous	1,266	1,433	1,357	-
	Total Sales Expenses	M$16,017	15,821	15,641*	10,000

* Includes M$335 for wage adjustment and M$27 for wage differential

The principal elements of sales expenses are labor, sales promotion, advertising, and administrative support. In applicant's estimate for 1972, $8,108,000, or slightly over one-half of forecasted sales expenses, is labor-related and provides for salaries and personal and auto expenses of personnel assigned to sales activities. Of the $7,452,000 remaining, $3,780,000 is forecast for advertising programs; $2,093,000 is for sales promotion; and $1,579,000 is for administrative support to the other activities. About 40 percent of the labor-related expenses and about $200,000 of sales promotion, or a total of approximately $3-1/2 million, are the result of service functions performed by sales personnel. Such service functions comprise the first of the three general objectives set forth below which applicant states are reflected in its level of sales expenses shown for the test year.

The three marketing objectives are: (1) to provide necessary service in connection with customers' use of gas; (2) to improve customers' utilization of gas; and (3) to maintain present market position for gas appliances and equipment. Marketing effort is now directed, applicant's expert witness states, towards customers having a necessary energy need, such as home heating, water heating, or cooking, the objective being to convince these customers to use gas rather than electric equipment with emphasis on conserving energy through the efficient application of fossil fuel resources. Promotion and advertising effort is no longer directed towards encouraging customers to add new gas load or to increase their present use of energy. This was discontinued early in 1971 in response to prevailing gas supply conditions.

The $12 million of forecasted 1972 sales expense remaining after assigning $3-1/2 million to service functions would be for the second and third marketing objectives, which are inter-related and not susceptible to a meaningful functional apportionment of dollars between these two objectives. A recasting of applicant's estimate of its sales expense for test year 1972 can be made, however, by market segments toward which promotional programs are directed, as follows:

Residential New Construction	$ 2,682,449
Appliance (Dealer Replacement Market)	2,571,917
Air Conditioning	1,653,648
Home Service	489,530
Food Industry	788,068
Industrial and Commercial	2,233,922
Subtotal	10,419,534
General Expense	3,897,122
Indirect Expense	1,201,000
Annualize Wage Increase	123,000
Total	$15,640,656

The staff's estimate of $10 million for sales expenses for test year 1972 represents a judgment as to the appropriate level of sales promotion expenditure for applicant. A primary consideration was the amount adopted for Southern California Edison Company in Decision No. 78802 dated June 15, 1971 in Application No. 52336, the Commission having made therein a substantial downward adjustment in the sales promotion expense of that company. The sales expense allowed to the Southern California Edison Company provides a specific basis of about $3.00 per customer upon which the $10 million allowance advocated by the staff in this proceeding can nearly be developed. Other factors considered by the staff witness were the competitive situation in Southern California, the larger advertising expenditures of national electric appliance manufacturers compared to the gas counterparts, the conservation of natural resources by using the more efficient fuel, and tempering the consumers' induced desires for appliances.

From a regulator's viewpoint sales promotion expenses, including advertising, may be legitimate allowable expenses of a public utility. But a determination of a reasonable level of sales expenses for rate-making purposes is often a difficult task. It usually requires the exercise of judgment because of difficulties inherent in measuring the effectiveness of promotional efforts or, put another way, because a given level of expenditures can seldom be tested with sufficient precision to ascertain whether or not benefits to ratepayers equal or exceed such expenditures.

In this proceeding one measure of the need for sales promotion is the exposure to loss of present market position for gas appliances and equipment and the consequences of such a loss. As to exposure, the evidence presented by applicant stresses the promotional effort by manufacturers of electrical appliances and equipment as an important factor, perhaps a formidable one. The consequences of a loss of market position include a lesser utilization of system facilities for firm service resulting in a reduction in both gross and net revenues under existing rate relationships between classes of service.

As to market position in its service area, according to applicant's witness, 77 percent of the residences use gas ranges, 94 percent use gas water heaters, and 93 percent use gas for home heating; in residential new construction, gas accounts for 50 percent of the ranges, 82 percent of the water heaters, and 73 percent of the space heating equipment.

During 1972 approximately 140,000 ranges, 200,000 water heaters, and 100,000 units of heating equipment are expected by SoCal to be sold to its present customers to replace old, worn-out gas equipment and approximately 85,000 new residences are expected to be built and occupied in its service area. The replacement appliances represent annual gas operating revenues of approximately $20 million and the new construction to be added to applicant's lines during 1972 represents an annual revenue of approximately $12 million. In the case of the replacement market the net revenue would be approximately 50 percent of the $20 million. In the case of the $12 million, which is new construction, the net revenue would be approximately 8 to 10 percent. Thus, applicant would estimate net revenues of approximately $165 million over a 15-year average life of appliances installed in these markets and points to this net revenue potential as economic justification for its forecasted 1972 sales expenses of $15.6 million.

In the opinion of applicant's witness any significant reduction of such forecasted expenses would result in an accelerated erosion of the present market share for gas appliances. In our view, applicant's market position is attributable to the history of gas use in its service area, to promotional efforts and probably to other factors as well. And the time is ripe for a substantial reduction in applicant's promotional activity.

Any increase in exposure to loss of market position because of such a reduction would tend to be mitigated in the short run by the carry-over effect of past promotional effort. More importantly, it will occur under the prevailing critical gas supply situation, one of such severity that it has caused applicant through its affiliates to embark upon a gas exploration and development program not only because of the need for new supply increments but also because the capability of applicant's principal gas suppliers to meet existing supply commitments is deteriorating.

After careful consideration of the record herein, we are convinced that both good regulation and good sense require an allowance for sales expenses for test year 1972 at a level substantially below the $15.6 million contended for by applicant. In our considered judgment an allowance of $12.6 million for applicant's sales expenses in test year 1972 is just and reasonable and we so find.

Pensions-Benefits

The finalized 5-1/2 percent wage increase discussed hereinabove affects certain employee pension and benefit costs. Consistent with our adopted allowance of $4,732,000 for the added wage expense from the wage increase, our adopted operating results for test year 1972 include in administrative and general expenses an allowance in the amount of $820,000 for the related increase in the employee pension plan and $63,000 for the increase in the medical plan. In addition, our adopted operating results include $300,000 of the $486,000 difference in estimates, as set forth in Exhibit 80, between applicant and staff for special retirement payments, retirement savings plan, life insurance refund, allocated system service group expenses, pensions and benefits billed to SoCal, and pensions and benefits capitalized.

In summary concerning operation and maintenance expenses, we find that such expenses in the total amount of $571,236,000, as adopted in Table 1, to be proper and representative of test year 1972 operations at "Present Rates".

<u>Taxes</u>

Applicant's estimate of taxes other than those on income exceeds the staff's estimate by $2,107,000.

As the principal difference, the staff deducted from its estimate of 1972 ad valorem tax the amount of $2,373,000 which is the amortization of a credit resulting from a change in accounting for such taxes from a calendar to a fiscal year basis. Another difference is the staff used later information regarding payroll tax rates which result in the staff's estimate of payroll taxes being $266,000 higher than applicant's estimate.

The staff's treatment of the ad valorem tax credit in its development of ad valorem taxes as well as in its development of a working cash allowance is appropriate in light of the coordinated basis upon which rates were fixed in applicant's recent general rate proceeding using test year 1970. At that time, the ad valorem tax included in the adopted operating results represented the accrual during the test year of the tax for the 1970/1971 fiscal year; the adopted working cash allowance reflected the lead in the recovery through revenues of such tax before payment.

We have adopted the staff's estimate of taxes other than those on income with a slight modification to reflect an increase in payroll taxes as a result of the 1972 wage increase.

In income taxes the major issues concern the use of the new investment tax credit (ITC) and the asset depreciation range (ADR) included in the U.S. Revenue Act of 1971. The term ITC refers to a reduction in current tax liability allowed by federal income tax authorities, pursuant to tax laws, based upon a stated percentage applied to the dollar amount of specified qualifying plant additions.

The ADR is the class life tax depreciation system. It permits more flexibility in estimating service lives of assets for computing the depreciation deduction allowable for federal income tax. However, ADR contemplates that the life used for tax depreciation should reasonably reflect the anticipated useful life of the class of property for the industry in which the taxpayer is included.

The new ITC results, as did its predecessor repealed by the U.S. Tax Reform Act of 1969, in a tax savings rather than a tax deferral. Consistent therewith, the staff included in the test year 1972 the effect of ITC on a full flow-through basis using the average of the five years 1971 through 1975, an averaging process followed by applicant under the prior ITC, which has the effect of smoothing out for rate-fixing purposes the variations of qualifying plant additions from year to year. Applicant excluded the ITC in its test year estimates. The staff's estimate of federal income taxes because of the ITC is $1,883,000 lower for SoCal than applicant's estimate. The impact on additional revenue requirements, if ITC is not flowed through, would be approximately double the $1,883,000 figure in achieving a given rate of return.

Full current flow-through of PLS Co's extraordinarily large ITC for 1972 on account of the Aliso Underground Storage Project would adversely affect the ability of the PLS Co portion of the PLU System to finance. SoCal is better situated than PLS Co in this regard and the staff's five-year averaging proposal mitigates the interest coverage (before taxes) and related financing problems of PLS Co.

The record in this proceeding makes it abundantly clear that if SoCal and PLS Co were merged a broader base for financing with more flexibility could result. Now that the plan to consolidate the employees of PLS Co into SoCal has been implemented, it would appear to behoove the managements of applicant and its utility affiliate to seek a merger of the two companies at such time as the indenture holders might agree to reasonable terms. It is difficult to see how such a merger, if consummated on reasonable terms, would not be in the public interest or would not facilitate regulation.

Of more immediate application, the adjusted capital structure of the PLU System, which we adopted hereinbefore in the discussion of fair rate of return, contemplates more equity financing to the extent of increasing the equity ratio from 36.3 percent to 39.3 percent and reducing in turn the debt ratio from 53.0 percent to 50.0 percent. With this objective for future financing of the PLU System, the indenture provisions concerning long-term debt interest coverage before taxes of PLS Co can be better met, all other things being equal. Moreover, if some deferral in long-term financing is necessary, currently interest rates on short-term debt are attractive in relation to cost rates for new long-term debt.

Our adopted operating results for test year 1972 reflect the staff treatment of flowing through the investment credit currently on a five-year average basis.

As to the ADR the staff recommends its use to modify (in effect shorten by 20 percent) guideline lives used in computing tax depreciation.4/ Applicant urges the Commission to establish rates

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4/ The depreciation deduction for the purpose of computing federal income tax payments by the PLU System generally is based on guideline lives, using a straight-line whole-life method for used acquisitions and for plant constructed prior to 1954, a double-declining-balance method for plant constructed subsequent to 1953, and a straight-line remaining-life method for investment in underground storage rights. The use of accelerated depreciation is on a "flow-through" basis for both accounting and rate purposes.

in this proceeding on the basis of present guideline lives for computing tax depreciation. To do otherwise, applicant contends, increases the present differences between book and tax depreciation, reduces the ability of PLS Co to issue new long-term debt and imputes a tax reduction which may not be realized under final regulations yet to be issued and/or under class lives yet to be finally determined by the Office of Industrial Economics.

This Commission has consistently held to the position that flow-through companies should continue to include in current-year income the tax effects of using liberalized depreciation including modifications thereof and we will not depart from that position here in regard to ADR. However, we reject the staff's use of lower limit ADR lives in calculating depreciation for state income tax purposes, since the record is clear that the ADR system has not been adopted by the State of California.

Based on the revenues and expenses, other than income taxes, adopted herein, we compute and adopt as reasonable under "Present Rates" for the test year an amount of $2,307,000 for state income tax (7.6 percent tax rate) and an amount of $10,910,000 for federal income tax, as shown in Table 1. Each amount reflects the use of accelerated depreciation on a "flow-through" basis. In the case of state income tax, present guideline lives were used for computing tax depreciation. In the case of federal income tax, the staff recommendation concerning the use of ADR has been adopted. That adoption has the effect of increasing the depreciation deduction allowable for federal income tax by $1,117,000. Certain other differences between applicant and the staff in the adjustments used in arriving at the bases for state and federal income tax calculations have been resolved consistently with the items to which they relate in our adopted operating results for test year 1972.

Rate Base

The difference between applicant and the staff in rate base is in the working cash component. It arises from the staff's deduction of the $5,932,000 unamortized deferred ad valorem credit balance at mid-1972 and the use of different revenue and expense estimates in the lag studies.

In connection with ad valorem taxes, we indicated hereinabove our concurrence in the staff's treatment of the unamortized ad valorem credit balance in developing a working cash allowance. Our adopted working cash allowance of $8,952,000 is consistent therewith and reflects the use of appropriate levels of revenues, expenses, and taxes in its determination.

As shown in Table 1, our adopted operating results of SoCal for test year 1972 yield at "Present Rates" a 6.59 percent rate of return on a rate base of $770,677,000. At this juncture, and before proceeding to a determination of the revenue deficiency in relation to an 8.0 percent rate of return for SoCal, we will turn to the operating results of PLS Co.

Pacific Lighting Service Company

As pointed out earlier herein, a determination of PLS Co's costs of operation must be made to determine in turn a substantial portion of applicant's production expenses. PLS Co's total cost of service equals its gross operating revenues which are the sum of its operation and maintenance expenses, depreciation expense, and taxes other than on income plus net operating revenues and income taxes. Its net operating revenues equals the product of its weighted average rate base and a fixed rate of return, presently 7.75 percent as fixed by Decision No. 77975 dated November 24, 1970 in Application No. 51567.

In Table 1 of Exhibit 79, the results of operation of PLS Co for test year 1972, as estimated by applicant and the staff, are compared and specific differences in their estimates are set forth. Further detail and explanation of these differences is provided in a companion exhibit, Exhibit 80. In Table 2 below, the comparative results of PLS Co's operation for test year 1972 at the existing rate of return of 7.75 percent, as set forth in Exhibit 79, are summarized and the operating results of PLS Co we adopt for the test year 1972 are shown at the existing rate of return of 7.75 percent and at the rate of return of 8.0 percent authorized herein.

A.52696 sjg/nb **

TABLE 2

PACIFIC LIGHTING SERVICE COMPANY

RESULTS OF OPERATION - TEST YEAR 1972

Item	At 7.75% Rate of Return				At 8.00%
	Staff	Utility	Utility Exceeds Staff	Adopted	Rate of Return Authorized Herein
	(Dollars in Thousands)				
Operating Revenues					
Gas Sales	$170,917	$175,883	$4,966	$171,201	$172,106
Other	1,773	1,833	60	1,783	1,783
Total Operating Revenues	$172,690	$177,716	$5,026	$172,984	$173,889
Operation & Maintenance Expenses					
Production	140,312	140,821	509	140,170	140,170
Storage	1,807	2,043	236	1,854	1,854
Transmission	3,780	4,001	221	3,856	3,856
Admin. & Gen'l	4,217	4,723	506	4,484	4,484
Total O. & M. Expenses	150,116	151,588	1,472	150,364	150,364
Taxes					
Taxes Other Than Income	3,707	4,129	422	3,849	3,849
Federal Income	523	3,078	2,555	1,361	1,763
State Income	217	463	246	259	327
Total Taxes	4,447	7,670	3,223	4,469	4,939
Depreciation	4,656	4,656	-	4,656	4,656
Total Operating Expenses	159,219	163,914	4,695	159,489	159,959
Net Operating Revenues	13,471	13,802	331	13,495	13,930
Affiliated Interest Adjnt.	6	6	-	6	6
Net for Return	13,477	13,808	331	13,501	13,936
Rate Base					
Working Cash	1,092	1,891	799	1,262	1,260
Unamortized Gas Devel. Costs	4,800	8,266	3,466	4,933	4,933
Remainder	168,008	168,008	-	168,008	168,008
Total Rate Base	$173,900	$178,165	$4,265	$174,203	$174,201
Rate of Return	7.75%	7.75%	-	7.75%	8.00%

Our adopted results reflect a consistent treatment of certain issues which are common to both PLS Co and SoCal, such as the staff adjustments for prospective wage increases, wage differentials, and ad valorem tax as well as basic expense estimates, ADR and ITC. These issues have already been dealt with and discussed at some length in the case of SoCal, making further comment on them appear unnecessary. In addition, the adopted results necessarily reflect appropriate resolution of other differences between the utility and the staff in their respective estimates. One of these other differences, in going to the issue of the proper allowance, if any, for rate-making purposes of the gas exploration and development program which is under way, requires discussion.

Through an affiliate, Pacific Lighting Gas Development Company (PLGD), PLS Co is pursuing an active and aggressive gas supply procurement program. As the initial or original part of this program, PLS Co has agreed to advance up to $15 million to PLGD for participation in a three-year, 1971-1973 inclusive, $30 million joint venture drilling program with a subsidiary of PLS Co's out-of-state supplier, Transwestern Pipeline Company (Transwestern). Its purpose is to augment gas reserves to support the present level of gas deliveries from Transwestern to PLS Co. On the basis of two discovery wells which have been brought in, the results thus far are encouraging.

Prior to the implementation of this joint venture drilling program PLS Co notified the Commission that it was the intent in its undertaking this project (through PLGD) for the consumer to bear the risks and costs and in turn to receive economic and gas supply benefits. Underlying such intent is the position of the Pacific Lighting group of companies that gas exploration and development activities are too speculative to undertake as their own capital risk investment. A proposal for the accounting to be followed for the project was thereafter made. It provides in part that all revenues, net after applicable taxes and operating expenses, received by PLGD will be flowed through to PLS Co and in turn to SoCal. Modification of the PLS Co cost-of-service tariff to incorporate this accounting, including a five-year amortization of project costs, was approved by the Commission by Resolution No. G-1522 dated May 25, 1971.

In their respective showings in this proceeding the company and the staff differ as to the proper amount to be included for this project in the 1972 test year rate base and the period over which its costs are to be amortized. The difference amounts to about $2 million in revenue requirements and is attributable, in essence, to the company's reflecting the full three-year project on a pro forma basis into the test year and using a five-year amortization period vis-a-vis the staff's reflecting only the first two years of the three-year project and using a five-year amortization period applied as expenditures occur.

In addition to the joint venture drilling project, PLS Co's gas development activities through PLGD now include a Gas Arctic Pipeline Feasibility Study, Arctic Islands exploration, and Central and South America exploration. The test year costs associated with this expansion of the gas development program, for which expenditures of $3,673,000 are projected through year-end 1972, were also included by the company and by the staff in their presentations during the course of the proceeding. The company and the staff differ as to the time of recovery of the costs of these activities, with the company using a five-year amortization period and the staff a 10-year period of amortization.

To facilitate comparisons of the treatment recommended by the staff, the treatment recommended by the company, and the treatment reflected in our adopted operating results, the following tabulation sets forth the impact on cost of service of the joint venture drilling project and the expanded gas development activities separately.

Pacific Lighting Service Company
Gas Exploration and Development Program

Test Year 1972
(Dollars in Thousands)

Item	Staff	Company	Adopted
	Joint Venture Drilling Project		
Revenue Requirement	$2,286	$4,340	$1,937
Amortization	832	1,560	780
Federal Income Taxes	1,014	1,925	859
State Income Taxes @7.6%	173	330	147
Return	267	525	151
Rate Base	3,450	6,772	1,950
Rate of Return	7.75%	7.75%	7.75%
	Expanded Gas Development Activities		
Revenue Requirement	527	1,041	481
Amortization	148	384	-
Federal Income Taxes	234	462	213
State Income Taxes @7.6%	40	79	37
Return	105	116	231
Rate Base	1,350	1,494	2,983*
Rate of Return	7.75%	7.75%	7.75%

* Total 1971-72 expenditures of M$2,293 for Gas Arctic and 1/2 of M$1,380 for other projects.

The California Manufacturers Association (CMA) and the General Services Administration (GSA) oppose the rate-making treatment advocated by either the company or the staff, contending that shareholders, not customers, should bear the capital risk and that gas distributors, moreover, should not be involved in exploration and development. While these contentions in this controversial matter obviously have some merit, we see at this time a need for measures which can represent a departure from the traditional approach of producers' and pipeline companies' supplying their own venture capital.

The record in this proceeding is clear that the major suppliers of out-of-state gas to the PLU System have neither adequate reserves to support very far into the future their present level of deliveries nor prospective new sources of supply upon which to plan and offer supply increments which are needed to meet the near future growth in the gas requirements of the PLU System. With this outlook on the gas supply prospects from both El Paso and Transwestern and the critical gas shortage developing in many parts of the United States, the need for special or innovative measures is unmistakable. After careful consideration, the Commission is of the view that the staff's support of the concept, need, and basic program for gas development in the current serious gas supply situation is well placed except that one change in basic concept is needed. Conceptually, both SoCal and its customers at this critical time in gas supply procurement should participate equally in the risks and the benefits. Such participation by the utility will provide an incentive to its management which appears essential to the selection process necessary to undertaking only the more promising ventures under favorable terms and to exercising of the concomitant cost controls effectively.

Our adopted operating results fully reflect this equal participation. For the joint venture drilling project the three-year program is included in the test year on a pro forma basis and the period of amortization used is five years. For the expanded gas development activities, the entire 1971-1972 projected expenditures for Gas Arctic, a pipeline feasibility study as differentiated from exploration, are included in rate base as are one-half of the projected expenditures for this same period for the other projects. The amortization required to recover such investments is being deferred, however, until more is known about the duration and outcome of these projects which relate to possible supplies some years hence to meet the requirements of gas customers in future periods. In addition to the deferral being appropriate because these projects are in the formative stages, it serves to mitigate the burden on present ratepayers by deferring the recovery of outlays associated with prospective gas supplies some years away.

In summary on this issue, PLU System is being thrust into gas exploration and development programs because of inability of out-of-state suppliers to replace gas supplies currently being expended from presently known reserves and because these suppliers appear totally unable to meet increased gas demands. These undertakings by PLU SYSTEM are preliminary in nature and are also contingent upon the efforts of the rest of the gas industry to secure and develop new gas supplies. Consequently, there are uncertainties as to the total eventual financial requirements of the gas development program. It is from this background the concepts adopted in our operating results reflecting the current program to acquire future gas supplies have evolved. We recognize, however, that the gas supply situation is deteriorating and that it may be necessary in the future to modify these concepts to protect the long-range requirements of the gas consumers. In such case, the applicant will have the burden of proving the necessity of placing a greater risk to be borne by the ratepayer.

Before leaving PLS Co, some comments are in order on the Aliso underground storage project beyond those made earlier in relation to its creating an extraordinarily large investment tax credit and a related financing problem. In addition to being extraordinary in relation to the normal annual plant additions of PLS Co, both as to size of expenditure and type of plant, it is also a nonadditional revenue producing type of facility. Because of these characteristics, we have adopted the pro forma treatment for this facility, in the operational results of PLS Co for test year 1972, advocated by the company and the staff. Under this treatment, a roll-back to the start of the test year is applied to that portion of the Aliso project which is not expected to be in service until the latter part of 1972. Its effect in part is to increase rate base by $37,224,000 minus $25,980,000 or by $11,244,000. The need for this new underground storage facility in the test year is uncontested and a certificate of public convenience and necessity has been granted, Decision No. 79751 dated February 23, 1972 in Application No. 53097.

For the purposes of this proceeding, we conclude that a total cost of service of PLS Co for test year 1972 of $172,984,000 at the existing fixed rate of return of 7.75 percent and $173,889,000 at the 8 percent rate of return authorized herein is reasonable.

C - Rate Spread

Revenue Increase

We find that the levels of revenues, expenses, and rate base of Southern California Gas Company as set forth in our adopted operating results in Table 1 hereinabove are appropriate, after certain revenue-related modifications to expenses and rate base and after adjusting production expenses to reflect an 8 percent rate of return for PLS Co to determine SoCal's gross revenue deficiency under "Present Rates" and should be used for that purpose.

As shown in the Table 1 results, the net operating income of $50,791,000 equates to a 6.59 percent rate of return on the rate base of $770,677,000. This is less than a fair return for SoCal which, as found in a previous section of this decision, is 8 percent. A deficiency in net revenues under "Present Rates" of $10,559,000 results, requiring additional gross revenues of $23,232,000 per year.

The adopted operating results of SoCal at rates being authorized herein may be summarized as follows:

Adopted Operating Results

At Authorized Rates

Operating Revenues	$713,674,000
Operating Expenses	652,324,000
Net Revenue	61,350,000
Rate Base	766,858,000
Rate of Return	8.0%

Apportionment of Revenue Increase

The authorized increase of $23,232,000 over test year revenue at present rates remains to be spread appropriately among the various classes of service and customers within such classes. In addition, the rate design to be adopted herein should provide appropriately for the merger of rates applicable in the respective territories of former Southern California Gas Company and former Southern Counties Gas Company of California.

SoCal's present rate design was established through Decision Nos. 77975 and 77976, issued on November 24, 1970 in the 1970 test year general rate proceeding and Decision Nos. 78469 and 78470, issued on March 23, 1971, concerning offset and tracking increases. In the present proceeding SoCal proposes to apportion the additional revenue requirement through a uniform percentage increase to the various major classes of service. In concluding that a uniform percentage increase to the various customer classes is appropriate, SoCal gave consideration to such important rate-making factors as the history of rates, value of service or comparative cost of alternate fuels, allocated costs, competitive factors, socio-political factors, customer usage patterns, and level of service to various classes.

The staff is in general accord with this conclusion except as to steam-electric rates where it considers that a decline in gas supply represents a significant change in circumstances and should cause a redesign of rates. The major thrust of the staff position is quoted from Exhibit 24:

> "The company's proposal of a uniform percentage increase to all classes of customers appears reasonable with the exception of the steam plant class. A comparison of the average cost of basic gas with the rate proposed by the company for the G-58 schedule indicates this proposed rate is below the average cost of gas. The company in its exhibits has made a very specific point that they are now operating under a condition of a declining gas supply. No significant relief from this situation is foreseeable until 1975 at the earliest. In view of this new set of circumstances, it is believed improper to sell gas to any customer at below the average price of that gas; therefore, it is recommended that this rate be set at least equal to the average cost of the basic gas supply."

The CMA, SCE, SDG&E and the three cities of Glendale, Burbank and Pasadena oppose the rate spread proposals of SoCal and the staff primarily on the basis of cost allocation data and certain rate design considerations. In Decision No. 77975, supra, the Commission reiterated the limitation of cost allocation data on the PLU System.

> "As pointed out in Decision No. 75429 in the 1969 rate proceeding of applicant, the outlook does not appear promising for any single cost allocation method or array of such methods to provide results for the Pacific Lighting Utility System which could serve as more than at best an approximate guide within one of the important elements considered in determining reasonable rates for the various classes of service."

After careful consideration of the evidence in this record, we continue to hold that we do not have before us any method of cost allocation which meets satisfactorily the test of an equitable cost apportionment between firm gas service and interruptible gas service where certain measures of cost benefit appear indeterminate and rigorous cost findings probably cannot be made.

SoCal's proposed apportionment of the revenue increase, in our judgment, may not adequately reflect the tendency toward a reduction in the relative load equation capability derived from interruptible service as the average level of basic gas supplies remains constant or declines. Its proposal, in our judgment, definitely fails to reflect adequately the respective levels of service of the steam plant and regular interruptible classes in relation to the impact of the cost of alternate fuels resulting from such different exposures to curtailment. The staff's recommendation to the effect that no rate be set below the average cost of basic gas supplies offers the advantage of a readily determinable bench mark or floor. Its validity from a cost of service standpoint cannot be determined, however, because we do not have a valid cost allocation method as has been made abundantly clear herein as well as in earlier decisions.

Perhaps with diminishing load equation from interruptible service under declining gas supplies and increased underground storage, such a floor on interruptible rates should be eventually established. But at this time the staff's recommendation would also tend to exacerbate the shortcomings in SoCal's proposal as it relates to increases as between the regular interruptible and steam plant classes. After careful consideration of this record, it is our judgment that an equitable spread of increases to customer classes is set forth in the following summary:

Summary of Authorized Increases

Test Year 1972

Class of Service	Adopted Sales MMcf	Adopted Revenues at 4-9-71 Rates M$	Authorized Increase Amount M$	Per-cent	Cents Per Mcf	Avg. Rev. After Inc. Cents Per Mcf	Avg. Rev. After Inc. Cents Per Therm
General Service	432,804	457,406	13,795	3.02	3.19	108.87	10.271
Firm Industrial	13,516	9,415	371	3.94	2.74	72.40	6.830
Subtotal	446,320	466,821	14,166	3.03	3.17	107.77	10.167
Gas Engine	5,014	2,822	125	4.43	2.49	58.78	5.545
Regular Interr.	218,802	99,389	4,422	4.45	2.02	47.45	4.476
Steam Elec. Plnt.	207,275	73,537	2,756	3.75	1.33	36.81	3.472
Wholesale	101,675	45,543	1,763	3.87	1.73	46.53	4.389
Subtotal	979,086	688,112	23,232	3.38	2.37	72.65	6.854
Other Gas Rev.	-	2,330	-	-	-	-	-
Total Rev.		690,442					

The rates authorized herein and as prescribed in detail in Appendix B to this decision for the rate schedules applicable to the various customer classes, have been developed after considering all of the factors inherent in rate spread and rate design including cost of service within firm service categories and within interruptible service categories, customers' usage patterns, value of service, level of service to interruptible customers, and history of rates.

Firm Retail Service Excluding Gas Engine (Schedules G-1 through G-40)

Based upon the operational results for test year 1972 relied upon by applicant, the 8-1/2 percent rate of return which it advocates, and the uniform percentage increase to the various major classes which it proposes, SoCal in effect seeks to increase rates to general service customers by approximately 8.6 percent which is equivalent to an average increase of nearly 9.1 cents per Mcf. This compares with an authorized increase for the general service customer class of $13,795,000 which, as shown in the foregoing tabulation, represents a 3.02 percent increase over the adopted revenues at the 4-9-71 rates and is equivalent to an average increase of 3.19 cents per Mcf. A typical monthly increase for an average household using 100 thermal units of gas a month under Schedule G-1 would be 36 cents at the rates authorized herein.

SoCal also proposes a rezoning or regrouping of firm general service customers for assignment to rate schedules to accomplish uniformity in the rate zone treatment of the former SoCal and former So Counties respective territories. This proposal is in line with the Commission's directive in Decision No. 77010 authorizing the merger of Southern Counties Gas Company of California into Southern California Gas Company and is set forth in Table 20-N of Exhibit 8.

Under this proposal reasonable differentials between rates applicable in the various rate zones would be established and the number of general service schedules for the former SoCal territory would be reduced from 8 (Schedules G-1 through G-6 and G-8 and G-9) to 5 (Schedules G-1 through G-5) and for the former So Counties territory from 7 (Schedules G-11 through G-17) to 4 (Schedules G-11 through G-14). In addition, a consolidation of contingent offset charges is feasible which would in turn permit Schedules G-1 through G-5 after appropriate changes to span the coverage now provided by the 15 schedules.

SoCal's rezoning proposal, as modified to conform to a minor change per staff recommendation in Exhibit 24 concerning only five rate areas and as modified to implement a further reduction in number of schedules upon consolidation of contingent offset charges in parallel schedules for the former SoCal and So Counties territories, has been incorporated into the rates prescribed in Appendix B to this decision.

The design of Schedule G-10, a lower cost option to residential customers with very small monthly use, will also be modified, as proposed by applicant and concurred in by the staff, to provide a uniform break-even point in monthly charges at 30 thermal units as between each G-10 rate and the general service schedule applicable to that rate area. Another proposal by applicant in which the staff concurs is the closing of Schedules G-20 and G-40, which are applicable only in former So Counties territory, to new customers. While this closure would be consistent with the goal of consolidation of the former So Counties schedules with those of SoCal, there are some objections. GSA opposes the closing of Schedule G-20 and the CMA opposes a percentage increase to Schedule G-40 rates greater than for other firm schedules to facilitate an eventual elimination of Schedule G-40.

Schedule No. G-20, Multi-Family and Military Natural Gas Service, is a regularly filed tariff applicable to service of natural gas in the former So Counties territory to (1) multi-family dwellings where the primary usage is for residential use and (2) military establishments for the combined three uses of cooking, water heating and space heating. In the former SoCal territory, SoCal's regular schedules apply and accommodate this type of customer through their rate design. A comparison of Schedule G-1 and Schedule G-20 rates as of April 9, 1971, is as follows:

Regular Usage	Per Meter Per Month G-1	G-20
First 20,000 thermal units, per unit	-	6.872¢
First 2 thermal units or less	$2.75626	-
Next 28 thermal units, per unit	8.441¢	-
Next 970 thermal units, per unit	7.488 ¢	-
Next 2,000 thermal units, per unit	7.201 ¢	-
Next 17,000 thermal units, per unit	6.761 ¢	-
Over 20,000 thermal units, per unit	6.401 ¢	6.372¢

GSA contends that the Commission has no right or jurisdiction to authorize the closing of Schedule G-20. We reject such contention. Based on this record, we see merit in applicant's proposal to close Schedule G-20 to new customers, find such limited closure will tend to better serve the interests of all of applicant's customers and will not pose an unreasonable or undue burden on prospective customers. In the exercise of our continuing jurisdiction over regularly filed tariffs, SoCal's proposal in this regard will be authorized.

Schedule G-40, Firm Industrial Natural Gas Service, is also applicable only in the former So Counties territory. At this time, as a step toward consolidating the rate schedules of former So Counties with those of SoCal, both applicant and the staff propose a larger than average percentage increase for the G-40 schedule rates in order to bring those rates into closer alignment with the rates for comparable service in the rest of SoCal's territory. Under this proposal the G-40 schedule rates would be brought only part way to the level of rates in the extended blocking of SoCal's regular firm natural gas schedules and the G-40 schedule would be closed to new customers, the objective being the eventual elimination of this schedule.

The CMA opposes the proposed larger-than-average percentage increase for Schedule G-40 rates based on a comparison of allocated costs with rates. It advocates no greater than an average percentage increase to the G-40 schedule and a less than average percentage increase to the tail blocks of SoCal's regular firm natural gas schedules to achieve a closer alignment of rates.

It is applicant's position that considerations other than allocated costs are involved, one of which relates to the problem of customer classification and schedule applicability. About 2,700 customers are served under Schedule G-40 and according to a witness for applicant over half of these customers would fall into a commercial rather than a firm industrial category. It is applicant's further position that customers of both types have been served satisfactorily in the pre-merger SoCal territory under firm general service schedules with extended blocking since 1957, at which time a SoCal G-40 type schedule was eliminated, and that Schedule G-40 should be closed to new customers if the goal of consolidation of former So Counties schedules with those of SoCal is to be achieved.

A comparison of our authorized revenue increase for the "firm industrial" service class in the amount of $371,000, which represents a 3.94 percent increase over the adopted revenues at the 4-9-71 rates and is equivalent to an average increase of 2.74 cents per Mcf or 0.259 cents per thermal unit, with the 3.02 percent or average 3.19 cents per Mcf increase for the general service class, shows the relationship of such increases we deem to be proper at this time. In view of the much larger customer base in the pre-merger SoCal territory, the absence of a cost analysis by customer groups or rate blocks of SoCal's firm general natural gas service schedules and the general application of these schedules and their rate history, there simply is not justification for the lesser percentage increases to the tail blocks of those schedules which the CMA advocates to bring the Schedule G-40 rates and the SoCal firm natural gas regular schedules into closer alignment.

Applicant neither proposes nor will we authorize the elimination of Schedule G-40 at this time. However, we will authorize a closure of this schedule to new customers in light of its possible future elimination, problems with its applicability, and the goal of having comparable service schedules in both the former SoCal and So Counties territories.

<u>Gas Engine Service</u> (Schedules G-45 and G-46)

Applicant and the staff propose that the blocking, rate levels, and special conditions be made the same in each of these schedules. The changes required to accomplish this are set forth in Exhibits I and 12 and are unopposed. In addition, an appropriate consolidation of contingent offset charges would eliminate the need for two schedules.

Schedule G-46 should be canceled and Schedule G-45 appropriately modified to serve as the surviving schedule. The rates prescribed for Schedule G-45 in Appendix B to this decision reflect an annual revenue increase of $125,000 which represents a 4.43 percent increase, equivalent to an average increase of 2.49 cents per Mcf or 0.235 cents per thermal unit, for gas engine service.

Regular Interruptible Service (Schedules G-50 through G-53V)

The adopted rate levels for the regular interruptible class reflect in the aggregate an annual revenue increase of $4,422,000 which represents a 4.45 percent increase, equivalent to an increase of 2.02 cents per Mcf or 0.191 cents per therm. This percentage increase is larger than the percentage increase of 3.75 percent for the steam electric plant class, largely in response to the impact of the cost of alternate fuels resulting from such different exposures to curtailment of these two customer classes.

Applicant has proposed and the staff concurs in the cancellation of one regular interruptible service schedule and the closure of another to new customers. Schedule G-53 is proposed to be canceled and the present G-53 customers transferred to Schedule G-50. The competitive situation for which Schedule G-53 was designed to meet many years ago no longer exists. The customers to be transferred will not be significantly disadvantaged because the rate differential between Schedule G-50 and G-53 has narrowed during recent years. Schedule G-50T, which serves only a few customers, is proposed to be closed to new customers. Schedules G-53 and G-50T apply to the pre-merger SoCal territory and there have never been counterparts to these schedules in the former So Counties territory. Schedule G-50 and also Schedule G-53T, however, not only have such counterparts, Schedules G-51 and G-53V, respectively, but the rate levels in corresponding schedules are the same. A consolidation of contingent offset charges would warrant cancellation of Schedules G-51 and G-53V. The regular interruptible schedules being retained would thus be: Schedules G-50, G-50T (Closed) and G-53T.

These proposals together with an appropriate consolidation of contingent offset charges and certain other changes, which are minor in nature and are set forth in Chapter 20 of Exhibit 8, will be authorized.

In addition, there is a need under the declining gas supply situation to eliminate the existing options available to regular interruptible customers to switch to a different schedule for the purpose of reducing exposure to curtailment. SoCal will be directed to eliminate such options from its tariffs in a manner that will not preclude regular interruptible customers from converting to different schedules for other reasons, including situations where the higher level of service would not be the principal reason for the change.

<u>Remaining Customer Classes</u>

The adopted rate levels for the steam electric plant class reflect an annual revenue increase of $2,756,000 which represents a 3.75 percent increase, equivalent in turn to an increase of 1.33 cents per Mcf or 1.254 cents per M^2Btu. As previously pointed out, the impact of the cost of alternate fuels resulting from this class' exposure to curtailment in relation to the exposure of the regular interruptible class, exercises an important influence in spreading a revenue increase between these two classes of service.

The authorized revenue increase of $1,763,000 to the wholesale class of service pertains to Schedule G-60 under which service is provided to the City of Long Beach and to Schedule G-61 under which service is provided to SDG&E. The authorized rate levels prescribed in Appendix B to this decision reflect an annual revenue increase of $298,000 for Schedule G-60 which represents a 3.84 percent increase, equivalent in turn to an increase of 1.92 cents per Mcf or 0.181 cents per therm; and an annual revenue increase of $1,465,000 for Schedule G-61 which represents a 3.88 percent increase, equivalent in turn to an increase of 1.70 cents per Mcf or 0.160 cents per therm. These increases also have been influenced to some extent by the impact of the cost of alternate fuels in relation to curtailment exposure.

A number of changes concerning either the schedules or service contracts, or both, for the steam electric plant and wholesale customers are necessary and will be taken up after the following discussions of parity proposals and curtailment priority system.

D - Parity Proposals and Curtailment Priority System

Currently and for the next several years, the supply of gas will not be sufficient to enable SoCal to satisfy as high a percentage of interruptible requirements as it has been capable of doing in recent years. Under these conditions, equitable levels of service to interruptible customers pose an important and complex issue in this proceeding.

By way of background, the policy and objective of SoCal since the mid-1960's has been to attempt to purchase adequate supplies of natural gas so as to meet all of the needs of firm service customers and approximately 90 percent of the requirements of interruptible customers both wholesale and retail. With adequate supplies, all of the firm requirements, nearly 100 percent of the requirements of regular interruptible customers and nearly 85 percent of the requirements of the utility electric generation customers were satisfied.

The objective for such high levels of service remains unchanged but is now unattainable. Since 1969, the PLU System has not been able to contract for and in turn have certificated new increments of out-of-state gas. In addition, there has been a significant decline in the availability of California source gas. This has led to a sharp decline in the level of service to utility electric generating plants, particularly the three Schedule G-55 and the two Schedule G-58 retail utility electric generation plant customers. The cities of Burbank, Glendale and Pasadena take service for their steam electric generating stations under Schedule G-55 and SCE and Department of Water and Power of the City of Los Angeles (LADWP) take such service under Schedule G-58.

In 1971, the utility electric generation plants of SDG&E received about 72 percent satisfaction of requirements from gas while the retail utility electric generation plants dropped to about 55 percent. The gas supplies for the electric generation plants of SDG&E are purchased by the gas department of that company under Schedule G-61. SCE, LADWP, and the utility electric generation plants of SDG&E are the three largest utility electric generation operations served from the PLU System. By far the largest of the three is SCE having an estimated requirement of 294.3 M^3cf on the PLU System in test year 1972; DWP is next with a 142.3 M^3cf requirement in the test year; SDG&E follows with a requirement of 73.4 M^3cf in the test year.

In SoCal's proposal for parity of service the stated intent is to offer the opportunity for an approximately equal percentage satisfaction of the requirements of the three largest utility electric generating customers served from the PLU System including this type of requirement by SDG&E. SDG&E, of course, vigorously opposes this proposal, its primary position being that its entitlement to gas supplies for its utility electric generation plants should continue to be determined in relation to the contract volumetric rate of its own Schedule G-54.

The Commission's staff is in accord with SoCal's proposal with two modifications. The staff believes that a parity concept should apply to Burbank, Glendale and Pasadena utility steam electric operations as well as SDG&E, SCE, and LADWP. The other modification would prevent some of the gas presently going to utility steam electric plants being diverted to other customers. SoCal has concurred in the staff's recommendation that no class of customer other than the utility electric generation class should benefit from or participate in any gas made available by reason of bringing deliveries to SDG&E's utility electric generation plants to parity with SoCal's retail utility electric generation plant customers. If the Commission considers it appropriate, applicant does not oppose serving the three cities, presently on Schedule G-55, on a parity basis under another schedule such as G-58.

In its opening brief, SoCal provided the following history and background of service to utility electric generation and cement plant customers which in its opinion must be considered in evaluating its parity proposal.

> "Retail Schedule G-54 was authorized by the Commission in 1957 in Decision No. 54831. Many of the considerations in that proceeding and many of the 'ground rules' established by that decision were the source of much of the evidence that was reviewed in this current proceeding. At that time the utility electric and cement plant customers were in the same class and were served under Schedule G-54. One of the objectives of the G-54 schedule was to provide for a more nearly equal satisfaction of the requirements of the retail utility electric generation plant customers (Exh. GG, pp. 8-9). With the advent of the G-54 contracts, a higher level of service to this customer class was contemplated and achieved (Tr. 17/1694). The availability of this interruptible market permitted the contracting for additional volumes of out-of-state gas. As the result, distinct benefits have been made available for all customer classes. These increments enabled SoCal to achieve a high level of service for the interruptible classes, while at the same time assuring its ability to meet the long term requirements of the firm customers (Tr. 17/1694; 18/1699-1701).

"In 1958 service to San Diego's electric plants were (sic) also brought to parity with the retail plants (Exh. GG, pp. 8-9). Schedule G-54 stated the basis for the determination of priority for the retail customers as 4 M²cfd plus 50 percent of the remainder of the contract volumetric rate at the 'A' priority plus the balance of the contract volumetric rate at the 'S-1' priority (Tr. 18/1701). It also stated the limitation on the 'A' block as 15 percent of out-of-state gas. SoCal's G-54 schedule was controversial and exceedingly complex (Tr. 17/1646). The retail customers made it known that they desired to have a schedule where the terms were more clearly and simply stated than under Schedule G-54 (Exh. GG, pp. 10-11).

"In 1961 in Decision No. 62260 (Case 5924), the Commission indicated that service for utility electric generation plant customers should be separated from that for cement plants and other interruptible customers (Exh. GG, pp. 12-13; Tr. 17/1646). This set the background for additional changes in schedules and new schedules that were developed (Tr. 17/1645-1646). During this time period, a whole series of interim schedules were made effective. Among these were Schedules G-54L, and G-54S for the electric plants and G-54M for the cement plants (Tr. 17/1642-1644). Schedule G-55 came into existence in 1965 and Burbank, Glendale and Pasadena contracted under it at that time (Tr. 17/1644). The G-56 cement plant schedule was also authorized at that time and Schedule G-53T was also made available to the cement plant customers (Tr. 17/1668). Schedule G-58 was not adopted until 1967, at which time Edison and LADWP contracted under it (Tr. 17/1643). Burbank, Glendale and Pasadena elected to stay with their G-55 contracts. The G-54 contracts of Edison and LADWP remained suspended and inactive at the time the G-58 contracts were entered into."

Equal satisfaction of gas requirements from the PLU System for utility electric generation plants has not been proposed by either applicant or staff. From a practical standpoint, it appears that contractual considerations and departures of forecasted requirements from those which actually materialize as well as possibly operational factors including the relative customer-size and customer-load pattern would dictate somewhat unequal levels of service. The following tabulation of levels of service based on test year 1972 (excl. PG&E source gas) shows that this in fact is the result under the parity proposals of SoCal and staff:

	Applicant %	Staff %
SCE	43.3	46.3
LADWP	43.7	42.9
SDG&E	44.0	45.0
Burbank	28.3*	35.7
Glendale	31.1*	39.0
Pasadena	27.6*	34.8

* Not included in applicant's parity proposal.

It is SoCal's position in part that deliveries to SDG&E could be brought to parity of service in 1972 with the present G-58 customers without modification of the G-61 agreement subject to Commission concurrence. Such concurrence will be forthcoming because it provides a fair basis upon which to resolve the relative level of service which SDG&E is to receive for its utility electric generation plants. That level of service will be set to approximate the levels of service of SCE and LADWP and to be operative until such time as a higher level of service would result under the G-61 agreement.

Consistent with the G-61 agreement, the total annual deliveries to SDG&E including "make up" gas is intended to equal not less than the product of the contract demand of 221,000 Mcf per day times the 365 or 366 days in the year. This means that comparable levels of service with SCE and LADWP will be maintained only until the floor on level of service to SDG&E is reached as determined in relation to contract demand quantity. Thereafter, the level of service to SDG&E's utility electric generation plants would not, however, remain constant but would continue to decline as a result of growth in SDG&E's firm and regular interruptible customer requirements in relation to a fixed contract demand quantity of 221,000 Mcf per day.

Our treatment of SDG&E results in a distinguishable level of service to its utility electric generation plants, one which is derived in part from a parity consideration with SCE and LADWP resulting in an equivalent daily contract quantity of 157,100 Mcf per day for purposes of curtailment classification and in part from the fact that SDG&E is a wholesale customer with a contract demand of 221,000 Mcf per day providing a floor, as discussed above, below which the equivalent daily contract quantity is inoperative. Of course, SCE and LADWP also receive individually a different level of service which depends upon gas availability in relation to their requirements and their G-58 contracted for deliveries.

SDG&E is similar to SCE and LADWP in that it operates utility electric generation plants and purchases gas from SoCal. It differs in that it is a wholesale customer purchasing gas for resale to firm and interruptible classes of service and for use in its utility electric generation plants, contracts with itself in effect in establishing a contract volumetric rate for its Schedule G-54, has no independent sources of gas - SoCal being its only gas supplier, and operates an integrated gas system.

In test year 1972 the levels of service (excluding PG&E source gas) of SCE, LADWP, and SDG&E utility electric generation plants and related daily contract quantities employed for purposes of curtailment classification, as reflected in our adopted operational results, are as follows:

	Level of Service	Daily Contract Quantity
SCE	46.7	652.2
LADWP	43.3	293.5
SDG&E	45.4	157.1

We turn now to the cities of Burbank, Glendale and Pasadena, which take service for their municipal electric operations under Schedule G-55. Because of the gas supply shortage and the resultant increase in exposure to the penalty provisions in the G-55 contracts, SoCal gave notice prior to April 1, 1971 to terminate these contracts over a period of five years. The result of the short-terming of these contracts is that these three customers will experience a further decrease in the volumes of gas they receive because the contract quantity decreases 20 percent per year. The staff, the three cities, and applicant appear to agree that service henceforth should be provided to the three cities under the price and conditions associated with Schedule G-58 in order that all retail utility electric generation customers would be provided a level of service commensurate with their full contract quantities. We also agree. Thus, service to these three customers should be provided pursuant to a G-58 type contract with their contract quantities restored to the pre-short-terming levels and Schedules G-55 and G-55A should be terminated.

Under the changed gas supply conditions another important aspect of an equitable distribution of available gas supplies concerns the level of service to the regular interruptible customers, especially to the largest of these customers. Within this class there are 1,575 regular interruptible customers having a total requirement of 242.1 M^3cf in test year 1972. Some 26 or 27 of these customers account for 43.3 percent of this total requirement and are assigned to a curtailment priority (A-Block) having the most exposure to curtailment within this class. Because of a long established price-priority relationship, both rates and level of service to the A-Block regular interruptible customers are higher than those for the Schedules G-55 and G-58 customers. The average rate to regular interruptible customers at "A" priority at "present rates" is 39.8 cents per Mcf. At 1060 Btu, this rate converts to 37.5 cents per M^2Btu as compared with the G-58 schedule present rate of 33.455 cents per M^2Btu.

SDG&E contends that a proper extension of the parity concept advocated by SoCal, the "price-priority" relationship notwithstanding, would be to include the A-Block priority regular interruptibles with the utility electric generation plants in a common gas pool in order to develop comparable levels of service.

The record herein discloses that until the Spring of 1971 when they converted to regular interruptible Schedule G-53T, three of SoCal's four cement plant customers were served under its lowest priority of service schedule, Schedule G-56. As to size, the cement plant customers fall in the mid-range of SoCal's A-Block priority regular interruptible customers. Also, the Imperial Irrigation District, operating utility electric generation plants, has been provided service historically, in part at least because of its location, under regular interruptible schedules. Moreover, the very large regular interruptible customers appear to be experiencing substantial growth in their requirements and this together with their higher priority of service in relation to Schedule G-55 and G-58 customers will tend to widen the spread in their respective levels of service.

Based on our adopted test year 1972 operational results, which exclude the PG&E source gas, Schedule G-55 and G-58 customers and SDG&E's utility electric generation plants will receive a 45.1 percent level of service compared with a 78.7 percent for A-Block regular interruptible customers. This difference in levels of service is being mitigated somewhat for the time being by the PG&E source gas which is expected to be available only in 1972 and which increases the level of service to utility steam electric customers to 53.3 percent.

In summary, serious doubt has been cast in this proceeding upon whether the A-Block regular interruptible customers' share of gas supplies is equitable in relation to that of the utility electric generation plant customers. In the circumstances, the course that appears indicated within the limitations of this record is to make some allowance in rate spread, as we have done in reflecting to some extent the impact of the cost of alternate fuels in relation to curtailment exposure, for the further divergence being experienced in the relative levels of service to such customer groups and in addition to alert applicant and its A-Block regular interruptible customers that this is an area of inquiry which will warrant examination in depth in applicant's next general rate proceeding.

Curtailment Priority System

For more than 30 years Rule 23 has been the PLU System guide as to the general relationship of service to customer classes during a shortage of gas supply. In Rule 23, Section (d), the general basis for curtailment of interruptible service is set forth as follows:

> "1. Customers served under interruptible service schedules shall be classified in groups based on the average price paid by each customer, and curtailment shall first be made in the lowest price group. These groups shall be subdivided for curtailment purposes and, to the extent practical, curtailment shall be equalized among customers in each group by rotating curtailment among the subdivisions of the group. Curtailments which exceed the total volume of gas used by all customers in the lowest price group shall, in the same manner, be effected successively in the higher price groups. Restoration of interruptible service shall be made in the same manner, but inversely as to price groups."

Further detail regarding the determination of curtailment priority has been set out in some of the rate schedules, such as G-54, but not in others, such as Schedules G-55, 56 and 58 developed later - when it was well known by eligible customers how priorities were to be determined and the objective was to make these schedules and contracts less complex. Reports of curtailment, including the number of customers in various priority blocks, the daily potential for curtailment in each block, and the amount of curtailment imposed each month, have been and continue to be filed with the Commission each month pursuant to General Order No. 58-A. The results of curtailment, therefore, have been and are available for continuing Commission and customer review. In addition, in response to the staff's concern in this area, SoCal proposes to modify Rule 23 to set out more clearly the basis for determination of priority blockings and the method for imposition of curtailment. The proposed modification is contained in Exhibit 30.

SoCal will be directed to expand Rule 23 to include the rather extensive detail contained in Exhibit 30 together with such modifications as are necessary to be consistent with the limited parity treatment of SDG&E's utility electric generation plants adopted herein, an increase in the A-Block limitation for the utility electric generation customers including that type of requirement of SDG&E to 21 percent of out-of-state gas, a transfer of the G-55 customers to Schedule G-58, and a discontinuance of Schedules G-54, G-55 and G-56.

In this connection, the following daily contract quantities (DCQ) are to be used for purposes of curtailment classification of utility electric generation service in place of those shown in Supplement B of Exhibit 30.

Customer	Rate Schedule	DCQ M^2cfd
Southern California Edison Company	G-58	652.2
Los Angeles Department of Water and Power	G-58	293.5
City of Burbank Public Service Department	G-58	13.5
City of Glendale Public Service Department	G-58	10.0
City of Pasadena Water & Power Department	G-58	12.5
*San Diego Gas & Electric Company	G-61	157.1

* The DCQ of 157.1 M^2cfd is controlling only until the total annual deliveries to SDG&E is expected to decline to the product of 365 or 366 days in the 12-month period commencing November 1 of each year times the G-61 contract demand of 221,000 Mcf per day. The total annual deliveries is to be maintained at that level thereafter to the extent consistent with the G-61 contract and irrespective of the DCQ of 157.1 M^2cfd.

The establishment of the above DCQ's is consistent with their application in arriving at our adopted operational results for test year 1972 and provides a fair basis from which to determine henceforth curtailment classification for utility electric generation service. In addition, such establishment of DCQ's makes it neither necessary nor constructive, so long as there is minimal or no "S-2" gas availability, to settle the controversy which developed during the course of the proceeding as to whether or not the gas requirements input for such curtailment classification should be based on annual forecasts of such requirements or on the most recent annual requirements actually experienced, problem areas being involved with either basis. Commission approval must be sought to change these daily contract quantities.

E - Proposed G-58 Contract Revisions, Proposed Conversion of Schedule G-61 to Therm Rates, and Contingent Offset Charges

SoCal estimates that its deliveries to LADWP and SCE will fall below the periodic and annual quantities included in the G-58 contracts because of the gas supply shortage and its inability to contract for and have certificated additional increments of gas supply. It proposes in Exhibit 2 a revision to these contracts which will clarify them so that there is no question that the service thereunder is interruptible and that the delivery obligations in these agreements are subject to and limited by the curtailment priority system.

The G-58 contract was designed to create greater mutuality of obligations than under Schedule G-54.[5/] The Schedule G-58 service was within the framework of being able to contract for gas supplies to deliver the contract quantities, while still performing the necessary curtailment as dictated by higher priority operations. The proposed G-58 contract clarification is appropriate and should be made.

Commodity Rates on Therm Basis for Schedule G-61

As a result of the proceeding in Phase II of Application No. 50714 (also Application No. 50713) and Decision No. 76597 thereon issued December 23, 1969, the desirability of an appropriate conversion of Schedule G-61 to a therm basis was established. A major reason the conversion has not been made since then is because both applicant and SDG&E[6/] were not before us as they are now with general rate increase applications. In this situation, SDG&E's schedules for gas service can be converted to a therm basis so as to reduce the impact on SDG&E that would occur upon a further decline in heating value, if the commodity portion of SoCal's G-61 rate is converted at 1060 Btu to a therm basis.

We have considered and reject in the present circumstances SDG&E's contention that all rates and charges and the contract demand quantity in SoCal's Schedule G-61 be converted to a therm basis. The monthly facility charge and the monthly demand charge per Mcf of contract demand quantity are both related to fixed cost which in turn relates closer functionally to volumetric capacity than to

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5/ As pointed out earlier, Schedule G-54 has not been active for some time and is to be discontinued. The Schedule G-58 customers wanted it as a possible service to retreat to if they terminated their contracts under the conditions provided in G-58. It is no longer a workable, viable schedule.

6/ Application No. 52801 for a general increase in rates for gas service.

heating value. SoCal's other wholesale schedule (G-60) and Pacific Gas and Electric Company's schedules for resale gas service limit, and appropriately so, the therm basis to the commodity rates in those schedules. It is not unreasonable that wholesale customers bear some exposure to the risks and resultant impact of declining heating values.

The rates prescribed for Schedule G-61 in Appendix B to this decision are designed to yield total annual revenues of $39,243,000 based on the test year but exclusive of tracking increases after April 9, 1971, and the commodity rate of 34.716 cents per M^2Btu therein, to which such tracking increases are to be added, has been set at the same level as the rate in Schedule G-58.

Contingent Offset Charges

SoCal's rates for gas service include offset charges related to increases and decreases in cost of gas from El Paso Natural Gas Company and PLS Co (including California gas) as a result of F.P.C. Dockets Nos. RP69-6, RP69-20, RP70-11 and RP71-13 of El Paso and RP69-27, RP70-19 and RP71-1 of Transwestern Pipeline Company. Such offset charges are collected subject to refund and reduction depending upon the level of just and reasonable rates the Federal Power Commission ultimately determines in these dockets.

We have in several instances in this decision referred to tariff changes proposed by SoCal in response to Decision No. 77010 dated March 31, 1970 in Application No. 51657, which authorized the merger of SoCal and So Counties. Ordering Paragraph 9 in that decision states:

> "9. Within one year after the effective date of the merger herein authorized, Southern California Gas Company shall file a plan for rate consolidation whereby the rate schedules of the surviving corporation will be consolidated to provide uniform rates for like service within appropriate heating value districts and zoned rate areas."

Because of differences in contingent offset charges in rates applicable to pre-merger territories, SoCal proposed originally, as shown in Exhibits 8 and 12, parallel but separate rates applicable to the pre-merger territories. In a later exhibit, Exhibit 29, an appropriate consolidation of offset charges was developed by weighting the respective offset charges for each docket and class of service by the volumes upon which the offset charges were initially established.

No opposition was expressed to consolidation of offset charges. Their adoption for application prospectively, not retroactively, appears fair and equitable in light of parallel rate levels to be applicable to pre-merger territories. As pointed out earlier, this will substantially reduce the number of rate schedules required. Consolidated contingent offset charges, as prescribed in Appendix B to this decision, will be authorized.

F - Proposed Gas Adjustment Clause

The cost of purchased gas comprises about 60 percent of PLU System's operating expenses. For this reason, changes in purchased gas costs can have a very substantial effect upon earnings. Unless SoCal is allowed to offset purchased gas cost increases as they occur it may suffer an irretrievable reduction in earnings.

Since 1969, SoCal and PLS Co have experienced fluctuating changes in purchased gas costs due to changes in rates filed by their out-of-state gas suppliers. These changes have resulted both in basic rate increases by these suppliers and from so-called "tracking" increases. A "tracking" increase is one put into effect by the out-of-state supplier only to reflect an increase in the price it is required to pay for gas. Basic rate increases cover all other increases in pipeline supplier rates. The price of gas purchased from out-of-state suppliers is entirely subject to the jurisdiction of the Federal Power Commission.

SoCal is now required to respond to basic gas cost increases by filing formal applications with this Commission for authority to offset such increases in its costs. One of the reasons for this is that before such basic gas cost increases can be put into effect by the out-of-state gas supplier a suspension period of up to six months is normally invoked. With respect to supplier tracking rate increases which become effective on short notice, this Commission has permitted applicant to be time-responsive to such increases by authorizing offset rate increases through the use of the Advice Letter Procedure. This procedure was first established by Decision No. 76068 dated August 26, 1969 in Application No. 51055.

As a pertinent recent development, Orders Nos. 452 and 452-A issued April 14, 1972 and June 13, 1972, respectively, by the Federal Power Commission in Docket No. R-406 establish a procedure for establishing a purchased gas cost adjustment provision in Natural Gas Pipeline Companies' FPC Gas Tariffs to flow-through changes in their cost of purchased gas. In Order No. 452-A, it is stated that "The PGA clause is intended to be a complete replacement for the concept of purchased gas cost tracking authority heretofore utilized." Order No. 452, establishes, among others, a 45-day notice requirement of any PGA rate changes and a requirement that rate changes not be filed more frequently than semi-annually to reflect the current cost of producer purchases.

Under its proposal in this proceeding SoCal would include a purchased gas adjustment provision in its tariff schedules or, in the alternative, adjust its rates pursuant to an enlarged Advice Letter Procedure to offset any change in the cost of purchased gas attributable to changes in the prices charged to SoCal by its suppliers. Changes in gas cost to SoCal from any supplier source

Including basic rate increases of out-of-state suppliers thus fall within the scope of either the proposed purchased gas adjustment provision or the proposed enlarged Advice Letter Procedure alternative. Many of the parties to the proceeding, including the Commission staff, consider the existing tracking and offset procedures afford ample protection for applicant with regard to increases in the cost of gas purchased from suppliers regulated by the Federal Power Commission.

SDG&E, however, supports a purchased gas adjustment provision or an enlarged Advice Letter Procedure for SoCal but would modify the proposed uniform cents-per-unit rate spread applicable to such adjustments because it reflects unaccounted for gas, franchise taxes, and uncollectibles on a system average basis. Such treatment of these comparatively minor items is neither unreasonable nor improper in fixing rates.

The staff supports spreading henceforth the changes in gas cost on a uniform cents-per-therm or thermal unit basis as proposed. Such a spread for the future is not incompatible with the concept of rolled-in pricing for eventual new increments of gas supply and will prevent any further departure in rates for the largest interruptible customers from the average cost of basic gas supplies.

After careful consideration, it is our view the existing Advice Letter Procedure[7/] should be retained with two important changes, however. The spread of tracking-type increases to customer

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7/ Decision Nos. 80182, 79515, 78469 and 77101 in Application No. 51567 and Decision No. 77100 in Application No. 51568.

classes should be changed for such future increases as occur to a uniform cents-per-therm or thermal unit basis and be determined consistent with test year 1972 gas purchase and sales volumes adopted herein. The cost of gas changes and required revenue offset resulting from 0.1 cents per Mcf change in El Paso rates and in Transwestern rates, respectively, have been developed based on the adopted total gas purchases of 1,000,805 M^2cf and total sales of 979,086 M^2cf for test year 1972 and are set forth in Appendix C of this decision. As the other change, SoCal's authority to adjust its rates pursuant to that procedure should be extended to and including December 31, 1973 and expanded to encompass both the existing tracking authority obtained by El Paso and Transwestern from the Federal Power Commission as well as future increases of this type which may result from purchased gas adjustment clauses of those companies if such clauses evolve pursuant to that Commission's orders (Docket No. R-406, supra).

Before proceeding to our findings and conclusions and the order herein, we should point out that it is not practicable in a proceeding as extensive as this one to rule individually on all the various points brought before us for consideration. Our objective has been to discuss and rule on those matters which seemed of major importance in deciding the validity of applicant's requests. However, broad consideration has been given to all matters though each may not be specifically treated herein.

Findings

1. In this application SoCal's request for a general increase in rates is in the amount of $64.2 million above the rates in effect April 9, 1971.

2. Prior to this proceeding the operations of PLU System were last exhaustively analyzed by the Commission in Application Nos. 51567 and 51568. Decision Nos. 77975 and 77976 were issued thereon November 24, 1970. The test year used was 1970.

3. The year 1972 is reasonable and appropriate to serve as the test year in this proceeding.

4. The adopted estimates in Tables 1 and 2 of the foregoing opinion, as discussed in that opinion, of operating revenues, operating expenses and rate bases of SoCal and PLS Co for the test year 1972 are appropriate to determine SoCal's gross revenue deficiency under present rates and should be used for that purpose.

5. SoCal's earnings under "Present Rates" from its operations during the 1972 test year produce a rate of return of 6.59 percent on a rate base of $770,677,000.

6. A rate of return of 8.0 percent for the PLU System is reasonable. A corresponding return on common equity under the adjusted capital structure adopted would be 11.65 percent.

7. A fixed rate of return for PLS Co for application in its cost-of-service tariff of 8.0 percent on its rate base of $174,201,000 is reasonable.

8. SoCal is in need of additional revenues but the increases it requests would be excessive.

9. SoCal is entitled to increases of $10,559,000 in net annual revenues to raise its test year rate of return from the present 6.59 percent to the 8.0 percent hereinabove found to be reasonable.

10. An increase of $23,232,000 in annual gross revenues based upon the test year 1972 is justified. Accordingly, applicant should be authorized to increase its existing gas rate levels to the extent indicated in Appendix B hereto so as to yield additional annual gross revenues in the amount of $23,232,000 based upon the test year.

11. The authorized increase is consistent with Rule 23.1, effective August 2, 1972, of the Commission's Rules of Procedure:

a. The increase is cost-justified and does not reflect future inflationary expectations;

b. The increase is the minimum required to assure continued, adequate and safe service and to provide for necessary expansion to meet future requirements;

c. The increase will achieve the minimum rate of return needed to attract capital at reasonable cost and not to impair the credit of the PLU System;

d. The increase does not reflect labor costs in excess of those allowed by policies of the Federal Price Commission;

e. The increase takes into account expected and obtainable productivity gains.

12. All classes of service should bear a portion of the required revenue increase of $23,232,000.

13. The rates authorized by this Commission as set forth in Appendix B hereto reflect a fair and reasonable apportionment of the authorized increase in gross revenues of $23,232,000 to the various classes of service.

14. As part of SoCal's proposed purchased gas adjustment provision or proposed enlarged Advice Letter Procedure alternate, it proposes to adjust rates for all classes of service on a uniform cents-per-unit basis to spread the changes in gas costs which occur. The concept of spreading henceforth the changes in gas cost on a uniform cents-per-therm or thermal unit basis is reasonable.

15. The existing tracking and offset procedures, as discussed in the foregoing opinion, afford protection for the PLU System with regard to increases in the cost of gas purchased from suppliers regulated by the Federal Power Commission.

16. Modification of the existing Advice Letter Procedure, as described in the foregoing opinion, is reasonable. Neither an enlargement of this procedure to the extent proposed by applicant nor a purchased gas adjustment clause appears necessary at this time.

17. The costs of the joint venture drilling project and the expended gas development activities are being shared as described in the foregoing opinion, and it is reasonable that an apportionment between SoCal, including its affiliates, and SoCal's ratepayers of the economic benefits in the form of net revenues or refunds, if any materialize from these projects, be made consistent with their relative participation in such costs.

18. Consolidation of rate schedules and contingent offset charges, discontinuance of certain rate schedules and closure of others to new customers, and other tariff modifications, as discussed in the foregoing opinion and prescribed in Appendix B hereto, is reasonable.

19. Conversion of the commodity rate in Schedule G-61 to a therm basis is proper, fair and reasonable.

20. It is SoCal's position in part that gas deliveries to SDG&E could be brought to parity of service in 1972 with the present G-58 customers without modification of the G-61 agreement subject to Commission concurrence. Our action taken herein provides such concurrence through Appendix B hereto which sets the level of service to SDG&E's utility electric generation plants to approximate the levels of service of SCE and LADWP until such time as a higher level of service would result under the G-61 agreement, as discussed in the foregoing opinion. In view of this action, it is not necessary to modify the G-61 agreement.

21. The modifications to the G-58 contracts proposed by SoCal, as set forth in Exhibit 2, to clarify these contracts are reasonable.

22. It is reasonable to make service available to the cities of Burbank, Glendale and Pasadena under Schedule G-58 pursuant to

a G-58 type contract with their contract quantities restored to the pre-short-terming levels.

Based upon consideration of the record and foregoing findings the Commission concludes as follows:

1. The application herein should be granted to the extent set forth in the preceding findings and in the following order and in all other respects should be denied.

2. The increases in rates and charges authorized herein are justified.

3. The rates and charges authorized herein are just and reasonable and present rates and charges, insofar as they differ therefrom, are for the future unjust and unreasonable.

4. SoCal and its affiliates should continue to keep the Commission's staff fully informed of the status of on-going gas development projects and proposed new ventures under their gas exploration and development program by periodic special reports and conferences.

5. All motions consistent with these findings and conclusions should be granted and those inconsistent therewith should be denied.

6. The modifications to the G-58 contracts proposed by SoCal, as set forth in Exhibit 2, to clarify these contracts should be made.

<u>O R D E R</u>

IT IS ORDERED that:

1. Southern California Gas Company is authorized to file with this Commission, on or after the effective date of this order, revised tariff schedules with changes in rates, charges, and conditions as set forth in Appendix B attached hereto. Such filing shall comply with General Order No. 96-A. The effective date of the revised rate schedules shall be four days after the date of filing. The revised rate schedules shall apply only to service rendered on and after the effective date thereof.

2. The Advice Letter Procedure pursuant to which applicant adjusts its rates to offset certain changes in cost of purchased gas, as established or modified through Decisions Nos. 80182, 79515, 78469 and 77101 in Application No. 51567 and Decision No. 77100 in Application No. 51568, is further modified to require henceforth a uniform cents-per-therm or thermal unit rate spread as prescribed in Appendix C hereto. In addition, applicant's authority to adjust its rates pursuant to this procedure is extended to and including December 31, 1973 and expanded to encompass both the existing "tracking" authority obtained by El Paso and Transwestern from the Federal Power Commission as well as future increases of this type which may result from purchased gas adjustment clauses of those companies.

3. Schedule G-58 contracts shall be modified in accordance with Exhibit 2 in this proceeding.

4. All motions consistent with the findings and conclusions set forth above in this decision are granted and those inconsistent therewith are denied.

The effective date of this order shall be twenty days after the date hereof.

Dated at San Francisco, California, this 29th day of AUGUST, 1972.

I abstain:

Commissioner

President

Commissioners

APPENDIX A
Page 1 of 2

List of Appearances

Rufus W. McKinney, Frederick A. Peasley, K. R. Edsall, and Jack D. Janofsky, Attorneys at Law, for applicant.

Sherman Chickering, C. Hayden Ames, and Donald J. Richardson, Jr., by Donald J. Richardson, Jr., Attorney at Law; Gordon Pearce and Fred I. Fox, Attorneys at Law, for San Diego Gas & Electric Company, protestant.

Roger Arnebergh, City Attorney, by Charles E. Mattson, Deputy City Attorney, for City of Los Angeles; Rollin E. Woodbury, Harry W. Sturges, Jr., William E. Marx, William Seaman, James Trecarten, Dennis Monge and Robert J. Cahall, Attorneys at Law, and C. L. Hunter, for Southern California Edison Company; William L. Knecht and R. O. Hubbard, Attorneys at Law, for California Farm Bureau Federation; L. L. Bendinger, General Manager, by Edward C. Wright, Leonard Putnam, City Attorney, by Harold A. Lingle, Deputy City Attorney, for City of Long Beach Gas Department; Louis Possner, for the City of Long Beach; Roy A. Wehe, for the City of Long Beach and Imperial Irrigation District; Robert W. Russell and Manuel Kroman, for Department of Public Utilities & Transportation, City of Los Angeles; Arthur T. Devine, Deputy City Attorney, and John O. Russell, City of Los Angeles Department of Water & Power;

List of Appearances

Thomas G. Burns, Sr. and Edward Hall, for Utility Workers Union of America AFL-CIO, Local 132; Alex Googooian, City Attorney, for City of Bellflower; Robert F. Smith, Walter C. Leist, and P. M. Ahlstrand, for Union Carbide, Linde Division; Renn C. Fowler and Maurice J. Street, Attorneys at Law, for Office of General Counsel, General Services Administration, Washington, D.C.; Hugh M. Flanagan, Attorney at Law, for California Portland Cement Company; Alan Watts, Attorney at Law, for City of Anaheim; O'Melveny & Myers by Patrick A. Randolph and Donn B. Miller, for Cities of Burbank, Glendale and Pasadena; Kenton L. Parker, for City of Glendale, Public Service Department; Lynn McArthur, for City of Burbank, Public Service Department; Brobeck, Phleger & Harrison, by Gordon E. Davis, Attorney at Law, for California Manufacturers Association; Curtis M. Fitzpatrick, Chief Deputy City Attorney, for City of San Diego; J. A. Witt, City Attorney, by William H. Kronberger, Jr., Attorney at Law, for City of San Diego; Wendell R. Thompson, City Attorney, for Department of Water & Power, City of Pasadena, interested parties.

Elinore C. Morgan and Leonard L. Snaider, Attorneys at Law, and Melvin Mezek, for the Commission staff.

RATES - SOUTHERN CALIFORNIA GAS COMPANY

TERRITORY - Within former Southern California Gas Company and Southern Counties Gas Company of California Service areas.

Applicant's rates, charges, conditions, and rate areas are changed to the level or extent set forth in this appendix.

RATES AUTHORIZED EXCLUDING TRACKING INCREASES SUBSEQUENT TO APRIL 9, 1971[1]

TARIFF SHEET REVISIONS EXCLUDING DEFINITIVE RATE LEVELS, EXHIBIT 12, are adopted except as modified in this appendix. There shall be no references to the purchased gas adjustment in the tariffs. Certain of the changes in Exhibit 12 are explained or repeated herein for purposes of clarification.

Change the title of Schedules Nos. G-1 through G-5 to "GENERAL NATURAL GAS SERVICE", which is the title used under the existing Schedules Nos. G-11 through G-17.

GENERAL NATURAL GAS SERVICE

Rezoning, rate area changes, and consolidation of schedules from 15 rate zones to 5 rate zones are shown under "TERRITORY". Delete Schedules Nos. G-6, G-8, G-9, and G-11 through G-17.

The blocking of areas formerly served by Southern Counties Gas Company (under Schedules Nos. G-11 through G-17) are modified and extended to conform to the blocking within the areas formerly served by Southern California Gas Company (Schedules Nos. G-1 through G-6, G-8 and G-9).

APPLICABILITY

Delete specific references to Rule No. 30 in Schedules Nos. G-1 through G-5.

1 Applicant is authorized to add authorized tracking increases subsequent to April 9, 1971 until the effective date of its Advice Letter filing made pursuant to this order. A summary of such increases through July 1, 1972 is tabulated on page 12 of this appendix.

GENERAL NATURAL GAS SERVICE--Contd.

TERRITORY

The rate areas by rate zone proposed in Exhibit 8, Table 20N and partially described in Exhibit 12 are adopted with the following modifications:

1. Proposed Schedules Nos. G-11 through G-14 are changed to G-1 through G-4.

2. Change rate schedules as indicated for the rate areas tabulated below:

Rate Area Number	Designation	Rate Schedule Present	Rate Schedule Authorized
6	Palos Verdes	G-3	G-3
8	Transmission Pipelines-Castaic North	G-4	G-4
25	Santa Barbara County (West)	G-15	G-4
309	New Cuyama	G-5	G-4
401	Earlimart	G-4	G-4

RATES

Commodity Charge:

Regular Usage:	Per Meter Per Month G-1	G-2	G-3	G-4	G-5
First 2 thermal units, per unit	$2.95*	$3.01*	$3.06*	$ 3.18*	$ 4.06*
Next 28 thermal units, per unit	8.610¢	8.872¢	9.367¢	10.243¢	11.755¢
Next 970 thermal units, per unit	7.653	8.053	8.469	8.966	9.438
Next 2,000 thermal units, per unit	7.414	7.414	7.414	7.414	7.414
Next 17,000 thermal units, per unit	6.965	6.965	6.965	6.965	6.965
Over 20,000 thermal units, per unit	6.594	6.594	6.594	6.594	6.594

* Same text relating to space heating customers:

Minimum Charge:

	G-1	G-2	G-3	G-4	G-5
All customers except "space heating only"	$2.95	$3.01	$3.06	$3.18	$4.06
Space heating only customers:					
November through April	5.90	6.02	6.12	6.36	8.12
May through October	None	None	None	None	None

GENERAL NATURAL GAS SERVICE—Contd.

SPECIAL CONDITIONS

1. Delete from Schedules Nos. G-1 through G-5 Special Condition No. 1 relating to minimum charges in apartments and multiple dwellings which is contained in existing Schedules G-1 through G-6, G-8 and G-9.

2. Contingent Offset Charges Related to FPC Dockets

a. Refunds of contingent offsets for all classes of service shall be calculated separately for the periods prior to and subsequent to the consolidation authorized by this decision, as of the effective date of this order, based upon the offset charges in effect during these periods. The identification of customers formerly served under Southern Counties Gas Company of California shall be retained in order that the amounts refunded reflect the contingent offset charges in effect during the preconsolidation period. Section E.4.c. and Section E.4.d. of the PRELIMINARY STATEMENT shall be incorporated in the tariffs following the format shown on pages 3 to 5 of Exhibit 29 to show the appropriate contingent offset charges and to provide the basis for refunds of contingent offsets. Section E.4.c. shall contain offset charges updated to the effective date of this order prepared in the same manner as page 3 of Exhibit 29 to provide a basis of making refunds for service up to the effective date of this order.

Section E.4.c. shall also contain the following information:

Weighted average contingent offset charges updated to the effective date of this order, for the rate schedules contained in this appendix, prepared in the same manner as page 4 of Exhibit 29 to provide a basis for making refunds for service, after the effective date of this order, based upon previously authorized offset increases. Contingent offset charges shall be listed in the PRELIMINARY STATEMENT and not in any rate schedule.

b. Future contingent offset charges authorized by this Commission related to FPC Dockets and/or purchased gas adjustment clauses, if any, of El Paso Natural Gas Company and Transwestern Pipeline Company shall be uniform for all schedules, expressed as ¢/TU; ¢/Therm, or ¢/M²Btu or the equivalent thereof for wholesale customers. Any future increase authorized will be shown in Section E.4.c. of the PRELIMINARY STATEMENT. No future commodity charge will be expressed as ¢/Mcf.

GENERAL NATURAL GAS SERVICE--Contd.

Change the title of Schedule No. G-10 to "OPTIONAL RESIDENTIAL GENERAL NATURAL GAS SERVICE". The rate design has been modified to provide a uniform break-even point in monthly charges at 30 thermal units as between each G-10 rate and the GENERAL NATURAL GAS SERVICE schedule applicable in that rate area.

OPTIONAL RESIDENTIAL GENERAL NATURAL GAS SERVICE

TERRITORY

Within the rate areas where Schedules G-1 through G-4 apply.

RATES

Commodity Charge:

	Per Meter Per Month	
	First 2 Thermal Units or Less	Over 2 Thermal Units Per Unit
In rate areas where Schedule G-1 applies	$1.95	12.179¢
In rate areas where Schedule G-2 applies	2.01	12.429
In rate areas where Schedule G-3 applies	2.06	12.929
In rate areas where Schedule G-4 applies	2.18	13.821

MULTI-FAMILY AND MILITARY NATURAL GAS SERVICE

APPLICABILITY

Schedule closed to new customers as of the effective date of the order herein.

RATES

Commodity Charge:	Per Meter Per Month
	G-20
Regular Usage:	
First 20,000 thermal units, per unit	7.079¢
Over 20,000 thermal units, per unit	6.565

STREET AND OUTDOOR LIGHTING NATURAL GAS SERVICE

Schedule G-30 is applicable systemwide. Withdraw Schedule G-31. Add blocking to cover lamps of larger input rating.

TERRITORY

Applicable throughout the system.

STREET AND OUTDOOR LIGHTING NATURAL GAS SERVICE--Contd.

RATES

Rate "X" -- Lighting Service only Hourly lamp rating:	Per Lamp Per Month G-30
1.99 cubic feet per hour or less	$1.10
2.00 - 2.49 cu.ft. per hour	1.37
2.50 - 2.99 cu.ft. per hour	1.60
3.00 - 3.99 cu.ft. per hour	1.85
4.00 - 4.99 cu.ft. per hour	2.10
5.00 - 7.49 cu.ft. per hour	2.40
7.50 -10.00 cu.ft. per hour	2.80
For each cu.ft. per hour of total rated capacity in excess of 10 cu.ft. per hour	0.35

FIRM INDUSTRIAL NATURAL GAS SERVICE

APPLICABILITY

Schedule closed to new customers as of the effective date of the order herein.

RATES

Commodity Charge: Regular Usage:	Per Meter Per Month G-40
First 1,000 thermal units, per unit	7.796¢
Next 2,000 thermal units, per unit	7.006
Next 17,000 thermal units, per unit	6.548
Over 20,000 thermal units, per unit	6.112

SPECIAL RATES FOR AIR CONDITIONING USAGE
SCHEDULES G-1 THROUGH G-5, G-20 AND G-40

Air Conditioning Usage:	Per Meter Per Month May Through October
First 100 thermal units, per unit	6.348¢
Next 150 thermal units, per unit	5.585
Next 250 thermal units, per unit	5.122
Next 1,500 thermal units, per unit	4.741
Next 8,000 thermal units, per unit	4.390
Over 10,000 thermal units, per unit	4.287

A.52696 NB

GAS ENGINE NATURAL GAS SERVICE

Combine areas now served under Schedules Nos. G-45 and G-46. Delete Schedule No. G-46. New blocking differs from that of old Schedules Nos. G-45 and G-46.

TERRITORY

Applicable throughout the system, except within Rate Areas 125 and 359.

RATES

Commodity Charge:	Per Meter Per Month G-45
First 2,000 thermal units, per unit	6.336¢
Next 8,000 thermal units, per unit	5.564
Over 10,000 thermal units, per unit	5.204

SPECIAL CONDITION

Revise per page 29 of Exhibit 12 changing language on contracts and contract termination.

Delete Special Conditions in former Schedule No. G-46 (Consolidated with Schedule No. G-45) providing for aggregating meter reads for billing under certain conditions and as related to priority of service.

INTERRUPTIBLE NATURAL GAS SERVICE

Delete Schedules Nos. G-51, G-53, G-53V, G-54, G-54A, G-55, G-55A, G-56 and G-58A. No customers are presently served under Schedules Nos. G-54, G-54A, G-55A, or G-56. Schedule No. G-50T is closed to new customers. Schedules Nos G-51 and G-53 are consolidated with Schedule No. G-50. Schedule No. G-53V is consolidated with Schedule No. G-53T. Schedules Nos. G-55, G-55A and G-58A are consolidated with Schedule No. G-58.

These rate schedule consolidations involve the previously discussed consolidation of contingent offset charges and consolidation of territories.

CURTAILMENT OF INTERRUPTIBLE SERVICE - RULE 23

The amplification of Section (d) of Rule 23 contained in Exhibit 30 is adopted with the modifications contained on the following page.

CURTAILMENT OF INTERRUPTIBLE SERVICE, RULE 23--Contd.

a. The A Block limit for Utility Steam Electric Generation Service, including wholesale steam-electric requirements, shall be 21 percent of the then effective maximum contracted daily demand contained in the service agreements of Southern California Gas Company and its affiliate for the purchase of out-of-state gas. The daily contract quantities (DCQ) and rate schedules to be substituted for those shown in Supplement B of Exhibit 30 are as follows:

Customer	Rate Schedule	DCQ M^2cfd
Southern California Edison Company	G-58	652.22
Los Angeles Department of Water and Power	G-58	293.5
City of Burbank Public Service Department	G-58	13.5
City of Glendale Public Service Department	G-58	10.0
City of Pasadena Water and Power Department	G-58	12.5
*San Diego Gas & Electric Company	G-61	157.1

* The DCQ of 157.1 M^2cfd is controlling only until the total annual deliveries to SDG&E is expected to decline to the product of 365 or 366 days in the 12-month period commencing November 1 of each year times the G-61 contract demand of 221,000 Mcf per day. The total annual deliveries is to be maintained at that level thereafter to the extent consistent with the G-61 contract and irrespective of the DCQ of 157.1 M^2cfd.

Rule 23 shall be modified to reflect the curtailment classification for regular interruptible service based upon the rate schedule consolidations and rate levels contained in this appendix. Add the following footnote on the curtailment classification pertaining to Schedules Nos. G-50T and G-53T: Customers served under this schedule shall not obtain service under another interruptible schedule with a higher curtailment priority when such change in schedule is primarily to obtain a higher level of service.

SCHEDULE NO. G-50

APPLICABILITY

Eliminate exception of Rate Areas 120 and 122 from exclusion relating to utility steam-electric generating station service.

TERRITORY

Applicable throughout the system, except within Rate Areas 125 and 359.

SCHEDULE NO. G-50--Contd.

RATES

Commodity Charge:

Regular Usage:

		Per Meter Per Month: G-50
First	2,000 thermal units, per unit	5.919¢
Next	8,000 thermal units, per unit	5.482
Next	20,000 thermal units, per unit	5.290
Next	30,000 thermal units, per unit	5.106
Next	40,000 thermal units, per unit	4.924
Next	100,000 thermal units, per unit	4.781
Over	200,000 thermal units, per unit	4.669

Special Rate for Air Conditioning Usage
May through October

First	2,000 thermal units, per unit	4.699¢
Next	8,000 thermal units, per unit	4.298
Over	10,000 thermal units, per unit	4.200

SPECIAL CONDITIONS

Delete Special Condition No. 5 of present Schedule No. G-51 (consolidated with Schedule No. G-50) regarding aggregation of gas deliveries to various premises of a customer.

SCHEDULE NO. G-50T

APPLICABILITY

Schedule closed to new customers as of the effective date of the order herein. Eliminate exception of Rate Area 122 from exclusion relating to utility steam-electric generating station service.

SCHEDULE NO. G-50T

RATES

Commodity Charge:

Regular Usage:

		Per Meter Per Month: G-50T
First	440,000 therms, per therm	4.667¢
Next	660,000 therms, per therm	4.535
Over	1,100,000 therms, per therm	4.371

INTERRUPTIBLE NATURAL GAS SERVICE--Contd.

SCHEDULE NO. G-53T

TERRITORY

Add Rate Areas 12 through 28.

RATES

Commodity Charge:

	Per Meter Per Month G-53T
Regular Usage:	
First 440,000 therms, per therm	4.258¢
Next 660,000 therms, per therm	3.983
Over 1,100,000 therms, per therm	3.840
Special Rate for Air Conditioning Usage, May through October:	
Applicable to Schedules Nos. G-50T* and G-53T*:	
First 11,000 therms, per therm	3.973¢
Next 11,000 therms, per therm	3.827

* Air Conditioning tonnage allowance reduced from 55 to 53 therms per ton.

SPECIAL CONDITIONS

Delete Special Condition No. 4 of Schedule No. G-53V (consolidated with Schedule No. G-53T) increasing rates for not extending the term of the contract.

SCHEDULE NO. G-58

NATURAL GAS FUEL FOR UTILITY ELECTRIC GENERATION

TERRITORY

Combine areas listed on pages 58 and 59 of Exhibit 12.

RATE

The rate for all gas supplied under this schedule is 34.716¢ per million Btu.

WHOLESALE NATURAL GAS SERVICE

SCHEDULE NO. G-60

Revise to reflect changes filed with Advice Letter No. 837 and further modified below.

RATES

Monthly Demand Charge:

Per Mcf of Daily Contract Demand at 65,000 Mcf per day	$3.058

Commodity Charge, per therm:

Up to 42,500 Mcf on any day	3.2484¢

For usage between 42,500 and 65,000 on any day:

Up to accumulated usage of 915,000 Mcf during contract year	4.5691¢
In excess of 915,000 Mcf during contract year	6.7601¢
Minimum Annual Charge for Additional Peaking Demand	$147,500*

* Includes up to 20,500 Mcf of gas taken during winter period calculated at the rate of $7.195 per Mcf or up to 61,500 Mcf calculated at the rate of $2.398 per Mcf if taken during nonwinter period, without extra charge. Payment of the minimum annual charge for additional peaking demand shall be made at the rate of $41,500 per month with the December, January, February billings and at $23,000 with the March billing.

WHOLESALE NATURAL GAS SERVICE--Contd.

SCHEDULE NO. G-61

Revise to reflect changes filed with Advice Letter No. 833 and further modified below.

RATES

Monthly Facility Charge	$ 97,500
Monthly Demand Charge: Per Mcf of Contract Daily Maximum Demand at 221,000 Mcf per day	$ 2.3437
Commodity Charge, per million Btu	34.716¢
Additional Peaking Demand Gas: Annual Charge for 19,000 Mcf on any day during winter	$132,000*
Commodity Charge per million Btu up to a maximum of 565,000 Mcf for winter ...	50.960¢

* Payment of annual charge for additional peaking demand shall be made at the rate of $36,000 per month with the December, January and February billings and at $24,000 with the March billing.

SOUTHERN CALIFORNIA GAS COMPANY

SUMMARY OF TRACKING RATE INCREASES BY CLASS OF SERVICE
SUBSEQUENT TO APRIL 9, 1971 UP TO AND INCLUDING JULY 1, 1972

	Tracking Increases 4-10-71 to 7-1-72 inclusive		
	Thermal Unit Rates ¢/TU	Therm Rates ¢/Th	Other Rates
Firm Natural Gas			
G-1 through 6, 8 through 10	.161		
General Service			
G-10 through 17, 20	.161		
Firm Industrial			
G-40	.161		
Gas Engine			
G-45, 46	.131		
Regular Interruptible			
G-50, 50T, 51, 53, 53T, 53V	.131	.131	
Steam-Electric and Cement Plant			
G-54, 54A, 55, 55A, 56, 58, 58A		.0873[a]	0.960[b]
Wholesale: Long Beach G-60			c
SDG&E G-61			d

a. Increase in G-58 and G-58A = .873¢/M²Btu

b. Increase in G-54 and 54A Base Rates (¢/Mcf)

c. Increase in rates are: Demand $0.097/Mcf
Commodity 0.0873¢/Therm

d. Increase is 1.390¢/Mcf in commodity rate for regular deliveries.

APPENDIX C

Southern California Gas Company
(Including former Southern Counties Gas Company)

SUMMARY OF REVENUE CHANGES REQUIRED BY 0.1¢/Mcf CHANGES IN RATES OF VARIOUS GAS SUPPLIERS
(Test Year 1972)

(Excludes Special Contract of
Pacific Gas and Electric Company
Source gas purchase and sales)

Supplier	Required Revenue Change For 0.1¢/Mcf Change in Cost of Gas	Total Sales M^2cf	Required Change in ¢ Per Mcf	Therm/Thermal Unit Rates
	(a)	(b)	(c)	(d)
El Paso*	$668,481	979,086	0.0683	.00644
Transwestern*	286,600	979,086	0.0293	.00276

RATE SPREAD FOR ALL TARIFF FILINGS MADE HENCEFORTH PURSUANT TO THE ADVICE LETTER PROCEDURE

The required change in cents per therm/thermal unit, as determined in accordance with the above summary, shall be applied uniformly to all rate schedules except Schedule No. G-30.

* Includes related effect on purchases of California gas under monthly border price contract provisions.