LR/ds

ORIGINAL

Decision No. 77976

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of SOUTHERN COUNTIES GAS COMPANY OF CALIFORNIA for Authority: (a) to Increase Its Gas Rates to Offset Higher Costs Occasioned by an Increase in the Rates of Suppliers of Out-of-State Gas to the Pacific Lighting Utility System, (b) to Continue the Advice Letter Procedure for Tracking Increases in Purchased Gas Cost Based on Federal Power Commission Dockets Nos. RP70-11 and RP70-19, and (c) for a General Increase in Its Gas Rates.	Application No. 51568 (Filed December 19, 1969) Phase I -- Parts (a) and (b) Of Authority Sought As Set Forth in Title Phase II -- Part (c) Of Authority Sought As Set Forth in Title

(Appearances are listed in Appendix A)

OPINION IN PHASE II

In the Phase II portion of the above-entitled application, Southern Counties Gas Company of California (SoCounties)[1/] seeks authority to establish a general increase in its rates for gas service.

This application and Application No. 51567, filed concurrently by applicant's affiliate, Southern California Gas Company (SoCal), were consolidated for purposes of hearing and companion decisions in each of the two phases under which the authorizations sought have been divided. After public hearing held earlier this

1/ As of July 31, 1970, and pursuant to Decision No. 77010 dated March 31, 1970 in Application No. 51657, the merger between Southern California Gas Company and Southern Counties Gas Company of California has been consumated. Southern California Gas Company, as the surviving corporation, has adopted the effective tariff schedules of Southern Counties Gas Company of California.

year in Phase I, the Commission issued on April 14, 1970, Decision No. 77100 in Application No. 51568 and Decision No. 77101 in Application No. 51567 in which applicant and SoCal were granted authority to increase their rates for gas service in order to meet increased purchased gas costs as incurred relative to rate increases placed in effect by El Paso Natural Gas Company (El Paso) and Transwestern Pipeline Company (Transwestern).

Public hearing in Phase II of these applications was held in Los Angeles before Examiner Main during the period April 8 to May 29, 1970. Upon the conclusion of 14 days of public hearing within this period, the matters were submitted subject to the receipt of briefs mailed or filed on June 30, 1970.

Phase I Authority

Pursuant to authority granted in Decision No. 77100, supra, Southern Counties Gas Company of California:

(1) increased its rates and charges for natural gas service on April 16, 1970, so as to provide additional annual gross revenues of $7,775,000, based on test year 1970, to offset the increased cost of gas it purchases from El Paso, the so-called El Paso basic increase in FPC Docket No. RP70-11, and the related effect on the cost of California gas purchased from Pacific Lighting Service Company (PLSC);

(2) further increased its rates on June 16, 1970, to yield $8,929,000 of additional annual gross revenues based on test year 1970 in order to offset the increased cost of gas purchased from PLSC attributable to the increased cost of gas from Transwestern,

the so-called Transwestern basic increase in Docket No. RP70-19, and to the related effect on the cost of California gas;

(3) has further increased its rates from time-to-time through an advice letter procedure established for the purpose of tracking additional increases in purchased gas cost based on Dockets Nos. RP70-11 and RP70-19 occurring during 1970. The maximum potential annual increase under the tracking authority thus established for these dockets is $8,878,000;

(4) spread the above basic increases and tracking increases among the various class of service on a uniform average cents per Mcf basis subject however to one-third of the average being allocated to the steam electric generating plant service classification with the remainder compensated for by the general service and firm industrial service classifications.

It was recognized in Phase I that the spread of the above basic increases among classes of service might not be compatible with one which would result from an in-depth study of the rate relationships among the various customer classes. Such study was not undertaken in Phase I because of time limitations imposed by the then imminent basic increases by El Paso and Transwestern.

For purposes of rate spread in Phase II the starting point will be applicant's rates in effect for gas service on December 25, 1969, and the spread will therefore concern both the El Paso and Transwestern basic increases and the general rate increase sought in Phase II.

Phase II Request

Originally applicant sought in Phase II authority to increase its rates by $16,200,000 annually due to increases in costs other than the increased cost of purchased gas. During the course of hearings in Phase II applicant revised its request for an increase in annual revenues in Phase II downward to $11,807,000. This revision came about through exclusion of the federal income tax surcharge and applicant's accepting adjustments to its test year 1970 estimated operational results consistent with certain staff estimates. Applicant stresses that these adjustments were accepted in the interests of expediting the proceeding and without acquiescence in their propriety.

As the matter now stands, applicant seeks authorization to make effective basic rates which will produce revenues which exceed those from rates in effect on December 25, 1969, by $28,511,000 annually. The basic increases but not the tracking increases authorized in Phase I are included in this amount.

Applicant's Position

Applicant states that, in addition to repeated increases in the cost of gas, other costs have recently risen despite its continued efforts to keep them down. Applicant represents that it has improved the efficiency of its operations, but that these improvements are no longer sufficient to offset the higher expenses it is now experiencing related to wages, employee benefits, cost of capital, and other increased costs as a result of inflation. Applicant contends that, even with all increased gas purchased costs offset, the estimated rate of return for applicant in test year 1970, without the requested general rate increase, would be only 3.69 percent. It is applicant's position that it requires a level of rates which will produce a rate of return of at least 8 percent and, that this is the minimum level of fair rate of return for it.

Record in Phase II

Evidence was presented by the applicant and its affiliates, SoCal and PLSC, the Commission staff, the City of Los Angeles, the City of Long Beach, San Diego Gas & Electric Company, and others. Applicant and its affiliates and the Commission staff offered evidence relating to all phases of the Pacific Lighting Utility System (the combined system of applicant, SoCal, and PLSC) operations. The participation of other parties, including the City of San Diego, Southern California Edison Company, Los Angeles Department of Water and Power and California Manufacturers' Association, pertained primarily to rate spread or rate of return.

The record on applicant's general rate proposal shows that there are two principal issues to be resolved. These issues are: (1) What amount of gas service revenues has applicant demonstrated that it reasonably requires; and (2) how shall such revenues be spread among the several classes of customers.

Applicant's Earnings

The rates of return estimated by applicant and by the Commission staff for the test year 1970 are as follows:

Rate Level	Rate of Return: Applicant (Ex. #36)	Rate of Return: Staff (Ex. #45)
At rates in effect 12/25/69	3.69%	4.06%
At applicant's proposed rates as revised	8.00%	8.43%

The tabulation below compares the estimates of the results of applicant's operation for the test year 1970 as presented by the applicant and the staff. The results shown for applicant reflect its adoption of the test year gas balance sponsored by the staff including staff's estimates of gas sales and gas required for company use and applicant's acceptance of certain other staff estimates.

Accordingly, we find that the estimates of $250,186,000 for operating revenues, $587,000 for storage expense and $6,068,000 for transmission expense, which are not in contention as between applicant and staff, are reasonable and should be adopted.

Summary of Earnings

Test Year 1970
At Rates in Effect December 25, 1969

Item	Applicant	Staff	Adopted Operating Results
	(Dollars in Thousands)		
Operating Revenues			
Gas Sales	$249,185	$249,185	$ -
Other	1,002	1,001	-
Total	250,187	250,186	250,186
Operating Expenses			
Production	169,968	170,367	170,321
Storage	587	587	587
Transmission	6,068	6,068	6,068
Distribution	15,327	14,041	14,920
Customer Accounts	9,083	8,643	8,863
Sales	5,695	5,695	5,695
Administrative and General	14,598	14,329	14,008
Subtotal	221,326	219,730	220,462
Depreciation	10,545	10,545	10,571
Taxes	8,102	8,826	8,174
Total Operating Expenses	239,973	239,101	239,207
Net Revenue	10,214	11,085	10,979
Rate Base	276,946	273,150	274,078
Rate of Return	3.69%	4.06%	4.01%

Production Expenses

The production expenses of the Pacific Lighting Utility System depend in part upon the rate of return component in the cost of service tariff of PLSC under which wholesale natural gas service is provided to SoCal and SoCounties. In Appendix B attached to this decision the operational results of Pacific Lighting Service Company based on test year 1970 which we find reasonable and have adopted for the purposes of this proceeding are set forth.

The staff estimates higher production expenses than the applicant based on a higher derived rate of return for PLSC (4.51 percent by staff vs. 4.19 percent by applicant and its affiliates) which more than offsets applicant and its affiliates higher estimate of PLSC's rate base. Consistent with the staff gas balance and a 4.50 percent rate of return for PLSC, we find that an estimate of $170,321 for production expenses is reasonable and is adopted as shown in the above tabulated operating results.

Distribution Expenses

Applicant's estimate of distribution expenses for the test year is $15,327,000; the staff's estimate is $14,041,000.

Distribution expenses represent two areas of activity, distribution and customer service. The distribution activity covers principally operation and maintenance expenses of the physical distribution system including meters and regulators; the customer service activity covers expenses relating to work done on customers' premises. The labor component in these expenses predominates, accounting for roughly 70 percent of the total expenses.

Applicant and staff employed basically different methods of estimating distribution expenses. Applicant's witness testified that SoCounties estimates were prepared as follows:

> For Distribution Activity: "Estimates for distribution expenses were prepared by the appropriate functional areas. In general these accounts were estimated through development of unit cost factors which were applied to anticipated standard hours, footage of mains, number of services, or other units of work expected to be accomplished."
>
> For Customer Service Activity: "Basically these estimates were developed on a cost per meter basis using recorded costs for the 12-month period ended September 30, 1969, adjusted to the April 1, 1969 wage level and expected mean connected meters for both 1969 and 1970. The 1970 estimates were further adjusted by the accounting department to reflect wage rates expected to be in effect during 1970. An additional upward adjustment was made to reflect changes in our service policy and residential heating equipment and leak investigation procedures."

In estimating distribution expenses the staff witness used, in general, a basic method of trending which reflects the history of recorded expenses for the period 1964 through 1968 with such adjustments as were, in his judgment, fitting. With the trend developed from the 1964 through 1968 data the staff witness then estimated expenses for the year 1969 using in most instances ten months recorded data and two months estimated. To this 1969 estimate he added the slope of the trend developed for the period 1964 through 1968 to arrive at his 1970 estimates.

Applicant contends that the staff underestimated expenses for 1969, thus starting its test year estimate from too low a base, and that the staff's trend applied to that base does not adequately reflect either the 1970 wage increase or changes in service policy on residential heating equipment and leak investigation procedures. On the other hand the staff contends that applicant's expense budget approach is designed to reflect estimated actual expenditures in 1970 without identifying and adjusting, for rate fixing purposes, abnormal or non-recurring items.

After consideration of the entire record including the need for proper application of either applicant's or staff's basic forecasting method, each of which is reasonably sound, and the lack of a convincing or adequate basis upon which to make selective adjustments within either method, and the recent changes in system operations at the transmission level with attendant effect on allocations of supervision and engineering expenses, the imminent merger of SoCal and SoCounties, the pattern of wage increases through recent years and the changes in service programs, we find reasonable and adopt for the test year an estimate of $14,920,000 for distribution expenses.

Customer Accounts Expenses

Applicant's estimate of customer accounts expenses for the test year is $9,083,000, including provision for uncollectibles at December 25, 1969, gas rate levels; the staff's estimate is $8,643,000. These expenses include the cost of meter reading, billing and customer accounting activities, collecting, credit investigations and the provision for uncollectible accounts. Directly charged labor is the most significant item of expense in customer accounts expenses, accounting for about 60 percent of the total for such expenses.

The same general issues between applicant and staff that exist for distribution expenses are present in this category of operating expenses. Consistent with our treatment of distribution expenses we find as reasonable and adopt for the test year an estimate of $8,863,000 for customer accounts expenses.

Administrative and General Expenses

Applicant's estimate of Administrative and General Expenses for the test year is $14,598,000, including franchise requirements at December 25, 1969, gas rate levels; the staff's estimate is $14,329,000. The difference between the estimates is accounted for almost entirely by a reduction of $265,000 by the staff in the $577,000 research and development program as estimated by the applicant for the test year. Also requiring consideration, however, in this category of operating expenses is a staff witness's accounting recommendation concerning capitalizing a portion of pensions and benefits.

In their respective estimates of administrative and general expenses both applicant and staff treat pensions and benefits entirely as an expense. To give effect to capitalization of pensions and benefits applicable to construction payroll the staff's estimate of administrative and general expenses for the test year would be reduced by $528,000. The staff accounting recommendation in this regard is sound and its effect is adopted for rate fixing purposes.

As to applicant's research and development program the record is clear that expenditures for this program have increased markedly year by year since 1967. The largest budgeted expenditure within the program is one for developing a fuel cell (TARGET) and amounts to $117,000 in the test year. TARGET represents an accelerated effort and the staff considered amortizing its four-year cost over a longer period. On an eight-year amortization basis a more equitable distribution in the amount of $58,000 per year results for rate fixing purposes.

Viewed in the context of the research and development activities required in the gas industry, applicant's research and development program is not unreasonable and applicant appears to be pursuing worthwhile projects. Greater emphasis should be placed, however, on projects having the objective of mitigating air pollution or otherwise protecting the environment and on projects directed toward raising the heat content of natural gas served by applicant to its customers. In this regard we are not unmindful of the environmental considerations associated with TARGET and point out that the amortization of expenditures for this project merely provides a more appropriate spread of its cost for rate fixing purposes.

Our order herein will require the filing of quarterly reports to monitor progress of existing research and development projects and the character of new projects undertaken.

We find reasonable and adopt for the test year an amount of $14,008,000 for administrative and general expenses.

Depreciation Expense

Applicant's estimate of depreciation expense for the test year is $10,545,000; the staff's estimate is also $10,545,000.

Consistent with our adopted estimate of gas plant, we find reasonable and adopt for the test year an estimate of $10,571,000 for depreciation expense.

Taxes

In the area of taxes the difference between the applicant and the staff relates only to income taxes and concerns calculation of the interest deduction and the related taxes paid depending upon the estimated net revenue before income taxes. Thus for the purposes of this proceeding applicant accepted the staff estimates for the test year of taxes other than on income consisting of $8,429,000 in ad valorem taxes and $1,225,000 in payroll taxes. However, to be consistent with our adopted estimate of gas plant in service,[2/] the staff estimate of ad valorem taxes should be decreased to $8,426,000.

In the calculation of taxes based on income the staff used a year-end composite interest rate for combining short-term and long-term debt to determine the test year interest deduction. Applicant contends that it would be more proper to apply the year-end interest rate for short-term debt to the weighted average short-term debt during the test year and the year-end interest rate for long-term debt to the weighted average long-term debt during the test year. Had this been done the interest deduction used for SoCal would have been lower. The reason for the lower result is that the amount of long-term debt is relatively less at year-end compared to the average amounts of long-term and short-term debt outstanding during the test year and the year-end interest rate for long-term debt is substantially below the 8.5 percent rate derived for short-term debt.

2/ Ad valorem taxes are a function of gas plant in service at beginning of year.

The staff's use of a year-end composite interest rate for combined short-term and long-term debt to determine test year interest deductions for the calculation of taxes based on income is consistent with rate of return studies which involve in effect applying year-end capital cost rates with weighted average capital during the test year, in view of the relationship of such capital to rate base and the fact that the revenue requirement on which rates are to be based is, in part, the product of a rate of return and a weighted average rate base. In concept the staff approach tends to bring income taxes and rate of return, as elements of the total cost of service or revenue requirement, into synchronization. Without such approach, the allowance for income taxes within the revenue requirements for the test year would tend to become excessive the following year.

Based on the revenues and expenses found reasonable and adopted herein, we compute for the test year a negative amount of \$1,477,000 for income taxes at the rates for gas service in effect December 25, 1969. We find as reasonable and adopt for the test year an estimate of \$8,174,000 for total taxes.

Rate Base

The components of weighted average depreciated rate base for the test year as presented by the applicant and by the staff are compared below:

Weighted Average Depreciated Rate Base

Test Year 1970

Item	Applicant	Staff	Adopted
	(Dollars in Thousands)		
Gas Plant:			
Plant in Service - Beg. of Year	$371,875	$371,553	$371,440
Weighted Average Net Additions	8,562	7,571	8,630
Non-interest Bearing Const. Work in Progress	841	841	841
Total Wtd. Avg. Gas Plant	381,278	379,965	380,911
Adjustments:			
Contributions & Cust. Advances for Const.	(9,281)	(9,281)	(9,281)
Dep. Res. Gen. Plant	(96,062)	(95,875)	(95,888)
Other Reserves	(1,087)	(1,087)	(1,087)
Total Adjustments	(106,430)	(106,243)	(106,256)
Working Capital:			
Working Cash Allowance	1,000	(1,675)	(1,675)
Mats. & Supplies	1,098	1,098	1,098
Total Working Capital	2,098	(577)	(577)
Total Wtd. Avg. Depreciated Rate Base	$276,946	$273,145	$274,078

( ) - Red Figure

The difference in rate base as estimated by applicant and the staff arises from their respective estimates of gas plant in-service at beginning of year, weighted average net additions, depreciation reserve for gas plant, and working cash allowance.

To develop our adopted estimate for weighted average gas plant, end of year 1969 recorded gas plant and weighted average net plant additions reflecting plant budget estimates and pensions and benefits costs applicable to construction payroll have been used. We find the weighted average gas plant in the amount of $380,911,000 thus developed to be reasonable. We also find and adopt as reasonable the amount of $95,888,000 for the deduction for depreciation reserve which is consistent with the depreciation expense heretofore found reasonable.

As to working cash, applicant's allowance is based upon judgment without substantial supporting evidence. The staff's allowance also represents judgment but is developed through an analysis of operational cash requirements and deductions for amounts generated from operations and not supplied by investors. In the staff analysis the operational working cash requirement of $3,587,000 is offset by $5,262,000 resulting from an excess of credits received over credits extended. A negative working cash allowance in the amount of $1,675,000 results which represents funds supplied by employees, suppliers, and customers. This amount, not furnished by investors, is treated by the staff as a deduction in determining rate base. Its manner of developing and treating negative working cash allowance is consistent with Decision No. 67369, dated June 11, 1964, in Case No. 7409 re The Pacific

Telephone and Telegraph Company and Decision No. 75873, dated July 1, 1969, in Application No. 49835 of General Telephone Company of California. In Decision No. 67369, the justification for including a negative allowance for working cash in rate base was commented upon as follows: "Where, as in this case, the funds supplied to respondent by others than investors are greater than the amount required by respondent for working cash, and the excess amount is not deducted from rate base, customers would be unreasonably required to pay a return on funds supplied by them to defray reasonable expenses and taxes and to provide a reasonable return on invested funds."

The justification for including a positive allowance for working cash in rate base is to provide the investors a return upon that portion of their invested capital which is necessary in the utility's operations and upon which they would not otherwise receive a return. Applicant has failed to so justify its judgment amount for working cash; its contentions that the staff treatment of Federal Income Tax accruals in the "lead'lag" study is arbitrary and that the compensating bank balances used by the staff in assessing operational cash requirements fails to give reasonable recognition to its open account arrangement with its parent corporation, Pacific Lighting Corporation, remain on this record as merely contentions and appear to lack demonstrable merit.

We find as reasonable and adopt a negative allowance for working cash in rate base of $1,675,000 as developed by the staff.

The remaining components of the weighted average rate base which we have adopted are at the levels used by both applicant and staff. We find reasonable and adopt a rate base for the test year of $274,078,000.

Rate of Return

Applicant seeks a rate of return of 8.0 percent on its depreciated rate base and, together with its affiliates, a rate of return of 8.0 percent on the depreciated rate base of the Pacific Lighting Utility System.

In depth presentations on the reasonable level of rate of return were made by applicant and its affiliates, the staff and the City of Los Angeles. The witness for applicant and its affiliates recommended a range in rate of return of 8.0 to 8.25 percent, the staff witness recommended a range of 7.35 to 7.65 percent, and the witness for the City of Los Angeles recommended a rate of return of 7.35 percent.

The witnesses used different year-end 1970 capital ratios in their respective studies. Applicant and its affiliates and the City of Los Angeles employed the composite capital structure of the Pacific Lighting Utility System and, in a modified derivation, applicant and its affiliates attributed the preferred stock of Pacific Lighting Corporation, the parent corporation, to the capital structure of the Pacific Lighting Utility System. The

Commission staff derived the year-end capital ratios for its study from the capital structure of Pacific Lighting Corporation. In tabular form the year-end 1970 capital ratios used in the several studies are:

Year-end 1970 Capital Ratios

Item	Applicant		Staff	L.A. City
Long-term Debt	45.6%	45.6%	43.27%	45.6%
Short-term Debt	4.4%	4.4%	2.71%	4.4%
Preferred Stock	2.5%	12.0%*	11.00%	2.5%
Common Equity	47.5%	38.0%	43.02%	47.5%
Total	100.0%	100.0%	100.00%	100.0%

*Includes preferred stock of Pacific Lighting Corporation.

The rate of return witness for applicant and its affiliates calculated at 8.0 percent rate of return the earnings rate which would flow to common stock equity for the Pacific Lighting Utility System. In his calculation he used a year-end composite cost rate of 5.46 percent for debt. The resultant earnings for common stock are 10.78 percent based on the 47.5 percent equity ratio and a preferred stock cost rate of 6 percent. This increases to 12.34 percent on net common equity when the preferred stock of Pacific Lighting Corporation is attributed to the utility system and makes the effective cost rate of preferred stock decrease to 4.83 percent.

His rate of return recommendation takes into account the system's size, capital structure, growth potential, requirements for capital, effects of inflation, interest coverage, and the competition in its service area, as well as special factors, including the growing problem of obtaining additional gas supplies and the deterioration in heating values of its gas supplies generally.

As the principal support for his recommendation, the witness relies upon the test of earnings comparability. For purposes of this test, he used as a primary group 20 large natural gas operating utilities and as a second group, the 20 largest straight electric utilities. For the 5-year average, 1964-1968, the capital ratios for the primary group were approximately 54 percent debt, 6 percent preferred stock, and 40 percent common stock; the straight electric companies' capital ratios averaged about 52 percent debt, 8 percent preferred stock, and 40 percent common stock; the capital ratios of the Pacific Lighting Utility System averaged 43.6 percent debt, 13.6 percent preferred stock including Pacific Lighting Corporation's preferred and 42.8 percent common stock. The average earnings on common stock equity were 12.45 percent for the 20 gas utilities, 13.16 percent for the 20 electric utilities and 10.76 percent for the Pacific Lighting Utility System. The earnings on total capital were 7.63 percent for the 20 gas utilities, 7.68 percent for the 20 electric utilities and 7.10 percent for the Pacific Lighting Utility System. The times interest earned after taxes were 3.27 for the 20 gas utilities, 3.75 for the 20 electric utilities and 3.88 for the Pacific Lighting Utility System.

The staff financial witness does not rely primarily on the comparable earnings approach but uses it as a guide. The companies he used are ten of the largest gas companies and ten of the largest combination gas and electric companies. His recommended range in rate of return from 7.35 percent to 7.65 percent reflects his judgment as to the needs and circumstances of the Pacific

Lighting group of utilities. Based on the capital ratios of Pacific Lighting Corporation, his recommendation provides a range of return on common equity from 10.09 to 10.79 percent.

His recommendation reflects many of the factors considered by the financial witness for applicant and its affiliates. As partially offsetting to the effects of continuing inflation, the staff witness expressed the view that applicant and its affiliates will probably continue to realize gains through purchasing at substantial discounts their bond issues bearing lower coupon rates and disposing of them at par for sinking fund purposes, and observed that efficiencies and substantial operating costs savings are anticipated in time from the imminent merger of applicant and SoCal.

The rate of return witness for the City of Los Angeles did not use the comparative earnings test and stressed the deficiencies in his opinion of the applicant's evidence. He pointed out in essence that the problem with a comparative earnings test is two-fold in that first, a standard for comparison must be a proper and valid one and, second, valid comparisons must be made. In arriving at a recommended rate of return of 7.35 percent, this witness relied heavily upon this Commission's treatment of rate of return in the following decisions: Decision No. 74917, dated November 6, 1968 in Application No. 49142 of The Pacific Telephone and Telegraph Company; Decision No. 75873, dated July 1, 1969 in Application No. 49835 of General Telephone Company of California; Decision No. 76106, dated August 26, 1969 in Application No. 50363 of

Southern California Edison Company; and Decision No. 76655, dated January 6, 1970 in Application No. 50779 of The Pacific Gas & Electric Company.

His recommendation is intended to reflect a reasonable correlation between this Commission's recent rate of return allowance to the other major California utilities and the rate of return to be found reasonable for applicant and the Pacific Lighting Utility System in these proceedings. In his opinion, proper effect has been given to differences in capital structure, cost of imbedded debt, and risk. Other factors he has taken into consideration are the size, character, history and reputation of applicants, the adequacy of interest coverage, the burden on the consumers, and the return to the stockholder.

In the final analysis, the rate of return determination devolves upon the judgment of the Commission, after weighing the evidence presented by all of the experts who, by their testimony, have sought to advise the Commission, to determine and to set a fair and reasonable rate of return. Upon a full consideration of the record, we find and conclude that a reasonable range for the rate of return for applicant and the Pacific Lighting Utility System at this time is 7.65 to 7.85 percent. Such a range of return, when considered with the cost of debt money of 5.46 percent and preferred stock money of 4.83 percent, should produce returns on common stock equity attributable to the Pacific Lighting Utility 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.

Authorized Revenue Increase

The adopted test year results at December 25, 1969 gas rates yield applicant a 4.01 percent rate of return. This is less than a fair return. We will authorize applicant to increase its December 25, 1969 gas rates by the amount of $24,452,000 in the manner hereinafter described, which amount should yield applicant a 7.75 percent rate of return on the adopted rate base of $274,078,000 for the test year 1970. The adopted results at rates being authorized herein may be summarized as follows:

	Adopted Results At Authorized Rates
Operating Revenues	$274,638,000
Operating Expenses & Taxes	253,398,000
Net Revenue	21,240,000
Rate Base	274,078,000
Rate of Return	7.75%

Rate Spread

For purposes of an overall rate spread we are confronted with the task of allocating revenue requirements of $273,637,000 (exclusive of Phase I tracking increases) to applicant's various classes of service.

All classes, however, should bear a portion of the total increase with reference to the rates in effect December 25, 1969, but, as anticipated in Phase I, certain classes of service may receive a reduction in rates from those authorized in Phase I corresponding to the El Paso and Transwestern basic increases depending upon the rate spread adopted herein.

A comparison in tabular form of rate spread proposals by applicant and SoCal and the staff is provided on the following page. The factors considered by applicant and the staff in developing their respective spreads include cost allocation, value of service, competition, rate history and, in the case of applicant, its contractual obligation not to apply for an increase in rates for Schedule No. G-58 serving Southern California Edison Company and the Los Angeles Department of Water and Power which would exceed on a cents per Mcf basis one-third of the system average increase sought.

To the extent applicant relied on cost of service, its proposed rate spread reflects the results of its new cost allocation method called 'The Base Supply and Load Equation Method'. The staff does not advocate the use of any one cost allocation method and supports the concept of giving consideration to the range of results produced among several allocation methods including the one sponsored by applicant.

As pointed out in Decision No. 75428 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.

A. 51568 LR/ms *

COMPARISON OF STAFF AND COMPANY
RECOMMENDED INCREASES
TO CLASSES OF SERVICE

Company and Class of Service	Revenues at 12-25-69 Rates	Recommended Increases: Staff - Exh. 33A (Table 3A)			Recommended Increases: Company - Exh. 41			Relationship of % Increases To Class To Average % Increase	
	M$	M$	¢/Mcf	%	M$	¢/Mcf	%	Staff	Company
SOUTHERN CALIFORNIA GAS COMPANY									
Firm Natural Gas Service	254,383	20,921	7.65	8.2	29,196	10.68	11.48	1.03	1.09
Gas Engine	1,846	140	3.80	7.6	135	3.67	7.31	0.95	0.69
Regular Interruptible	54,322	4,634	3.37	8.5	5,746	4.18	10.58	1.06	1.00
Steam Electric and Cement Plts	46,191	3,272	2.27	7.1	3,148	2.18	6.81	0.89	0.64
Resale	6,576	248	1.60	3.8	233	1.50	3.54	0.48	0.33
Total	363,318	29,215	5.09	8.0	38,458	6.69	10.58	1.00	1.00
SOUTHERN COUNTIES GAS COMPANY									
General Service	136,114	13,834	9.56	10.2	18,334	12.67	13.47	1.12	1.16
Firm Industrial	7,675	354	2.87	4.6	666	5.40	8.68	0.51	0.75
Subtotal	143,789	14,188	9.04	9.9	19,000	12.10	13.21	1.09	1.14
Gas Engine	797	90	5.47	11.3	95	5.78	11.92	1.24	1.03
Regular Interruptible	19,910	1,689	3.41	8.5	2,305	4.66	11.58	0.93	1.00
Steam Electric Plants	49,247	3,491	2.27	7.1	3,351	2.18	6.80	0.78	0.59
Wholesale	32,453	2,949	3.40	9.1	3,760	4.33	11.59	1.00	1.00
Total	246,196	22,407	5.00	9.1	28,511	6.36	11.58	1.00	1.00

In the base supply and load equation method, the load equation feature adjusts rolled-in or common costs for service interruptibility. This is done by imputing the load equation contribution of interruptible service as an estimated additional or incremental cost charged to firm gas service and credited to interruptible gas service. The end-results of this cost allocation method are markedly influenced by the level of the imputed additional load equation costs. If it were assumed that such costs would have materialized at the level estimated for the system of about $28,000,000 without the load equation contribution of interruptible service, the imputation made would reflect the cost benefit to the firm service from the interruptibles. What is missing in this consideration, however, is its counterpart: a measure of the cost benefit of firm service to interruptible service, which exists because of firm service and receives over 50 percent of the gas volumes sold in the test year, for the gas supplies and facilities jointly used by all classes of service in warm years, average years and cold years, albeit subject to substantial curtailment in the case of certain very large interruptible customers. This is a serious shortcoming of the base supply and load equation method and serves to point out the difficulties experienced over the years in devising a 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.

We also observe that the base supply and load equation method, as was the case with the independent systems method used by applicant in the 1969 rate proceeding, reflects the system's capability to meet extreme peak-day firm requirements and to meet cold-year firm requirements plus cold-year deliveries to interruptible customers. To the extent these extreme peak-day (based on an occurrence experience of once in 30-odd years) and cold-year conditions are used, allocation results are not responsive to the use made of gas supplies and of system facilities in an average or test year and to the estimated results of operation for such a test year.

As an over-all rate design consideration in their respective proposals, applicant and staff have attempted to make the features of applicant's and SoCal's rates more nearly alike for comparable classes of service.

The rates authorized herein for the rate schedules applicable to the various customer classes have been developed after considering all of the factors inherent in rate spread, including cost of service, value of service, level of service to interruptible customers, and history of rates.

General Service (Schedules G-1 through G-7, G-10 and G-20)

Applicant proposes that $18,334,000 or 64 percent of its requested increase, be obtained from customers, who will require approximately 32 percent of the total gas sales in the test year. This is an average increase of 13.47 percent, or 12.67 cents per Mcf of gas estimated to be sold to this class of service. Under both applicant's proposed rates and the staff recommended rates, the initial block charges Schedules G-1 through G-7 would be increased substantially to cover a larger portion of the fixed costs of serving customers.

In view of the evidence, we will authorize increases in the rates in the firm natural gas service schedules estimated to yield additional annual gross revenues of $15,410,000 as compared with the rates in these schedules in effect December 25, 1969, based on gas sales in the test year. This is an average increase of 11.32 percent, or 10.65 cents per Mcf and 1.005 cents per thermal unit.

Apart from its requested increase in rates, applicant proposes and the staff supports the following changes concerning the firm natural gas service schedules: (1) eliminate separate "H" rates for heating only and in Schedule G-20 summer-winter rate differentials; and (2) establish a new schedule designated G-10, Optional Residential General Natural Gas Service. Schedule G-10 is intended to be a lower cost option to residential customers with very small monthly use and to be available as such in all rate areas. About 40,000 customers may find it advantageous to take service under this optional schedule.

We find the proposed modifications, including the establishment of Schedule G-10, to be reasonable and they will be authorized.

Based on a comparison of the authorized rates set forth in Appendix C hereof and of the basic increases in rates placed in effect pursuant to our decision in Phase I, with the rate levels in effect on December 25, 1969, a typical monthly increase for an average household using 100 thermal units of gas a month under Schedule G-1 would be $1.10 at the rates authorized herein or 52 cents above the Phase I rate levels.

Firm Industrial Service (Schedule G-40)

Applicant proposes to eliminate winter-summer rate differential and increase rates so as to produce a revenue increase of $666,000 equivalent to 5.40 cents per Mcf of estimated sales to the firm industrial customers.

We find and adopt as reasonable an annual revenue increase of $479,000, or 6.24 percent, which is equivalent to 3.88 cents per Mcf, based on estimated sales in this service classification for the test year. Consistent with our disposition of the winter-summer rate differentials in other schedules we find their elimination from Schedule G-40 to be reasonable and such elimination will be authorized.

Gas Engine Service (Schedules G-45)

Applicant proposes to eliminate winter-summer rate differentials, and to increase rates so as to yield an annual revenue increase of $95,000. This is a revenue increase of 11.93 percent from this service category and equates to an average increase of 5.78 cents per Mcf.

Applicant's proposal concerning the summer-winter rate differentials is supported by the staff and has not been contested on this record. Such proposal appears reasonable and will be authorized.

We find that an annual increase of $88,000 representing a 11.04 percent increase in test year revenues from the gas engine class of service is reasonable and will be adopted. This increases the average rate level for gas engine service customers by 5.35 cents per Mcf, making the average level 53.80 cents per Mcf(5.075 cents per thermal unit), based on gas sales in the test year.

Regular Interruptible Service (Schedules G-50 and G-52)

An annual increase of $2,305,000 is sought by applicant in rates for the regular interruptible service customers. This is approximately an increase of 11.6 percent for this classification, or an average increase of 4.66 cents per Mcf. This increase applies to 11 percent of the total gas estimated to be sold in the test year and represents approximately 8 percent of the total revenue increase requested of $28,511,000.

Proposed changes in Schedules G-50 and G-52 have been limited to increases in rate level and include a proposal to increase the minimum charge for Schedule G-50 to $100 per month, cumulative to $1200 per year, which is the present and proposed minimum charge in SoCal's Schedule G-50.

In view of the evidence, we find that an increase in rates for this classification to yield additional annual gross revenues of $1,910,000, which includes provision for increasing the minimum charge in Schedule G-50 as proposed, is reasonable and should be adopted. The authorized increases in rate levels set forth in Appendix C hereof reflect for this classification an average increase of 3.86 cents per Mcf, or a 9.59 percent increase based on the estimated sales of gas to regular interruptible customers in the test year.

Steam-Electric Generation Service

This class of service, covering Schedules G-54, G-55, and G-58, is made up of 2 steam-electric generating plant customers accounting for over 35 percent of the gas sales volume in the test year and by far the major contribution to both seasonal and peak-day load equation among the classes of service subject to curtailment. In test year 1970, the level of service is about 71 percent to the steam-electric generating plant customers excluding special contract deliveries. Including the special contract sales, the level of service increases to about 75 percent.

Applicant proposes essentially a uniform increase in rates, equal to one-third of the average cents per Mcf increase on the system, for gas delivered to its steam-electric generating plant customers. On this basis, an annual increase of $3,351,000 equivalent to 2.18 cents per Mcf and representing a 6.80 percent increase,is sought. This increase represents approximately 12 percent of the total revenue increase sought of $28,511,000 and applies to 35 percent of the total gas estimated to be sold in the test year.

On this record, we find an increase in rates for Schedules G-54, G-55, and G-58 to yield additional annual gross revenues of $3,342,000 to be reasonable. The authorized increases in rate levels set forth in Appendix C hereof reflect, in relation to the rate levels in effect December 25, 1969, for these schedules, an average increase of 2.18 cents per Mcf, or a 6.79 percent increase, based on the estimated sales of gas to this service category in the test year.

This finding should be viewed, however, in the context of our continuing concern that equitable rate levels for steam-electric generating plant customers are particularly sensitive to changes in the over-all gas supply/requirement relationship and to changes in the costs of applicant's gas supplies.

Wholesale Service to San Diego Gas & Electric Co. (Schedule G-60)

An annual increase of $3,760,000 is sought by applicant in Schedule G-60 rates. This is a revenue increase of 11.59 percent from its wholesale customer, San Diego Gas & Electric Co. (San Diego), and equates to an average increase of 4.33 cents per Mcf based on the estimated sales of gas to San Diego in the test year.

A cost allocation study is sponsored in this proceeding by San Diego which results in a substantially lower cost assignment to it than by the other methods in this record. Such a result is attributable to a basic departure from an integrated system and common gas supplies approach to cost allocation. Because of this departure the San Diego study is not a very reasonable guide for use in the spread of rates among classes of service.

Based on this record we find and adopt as reasonable an increase in Schedule G-60 rates estimated to yield additional annual gross revenues in the amount of $3,223,000. This is a 9.93 percent increase or an average of 3.71 cents per Mcf of test year gas sales to San Diego.

In response to Decision No. 76597 dated December 23, 1969 in Application No. 50714, applicant and San Diego have reached the following mutually acceptable basis for converting Schedule G-60 to therm rates: After two consecutive months with average BTU of gas deliveries to San Diego at 1050 Btu or less the conversion would be filed by advice letter; at that time, the demand charge, the facility charge and the commodity charge would be adjusted to a therm basis at 1050 Btu; the contract demand level would continue to be on a volumetric basis.

The staff urged that the rates for sales to San Diego Gas & Electric Company, like the rates for all other classes of service, be converted to a therm basis and that the conversion be made at the present time. The staff proposed that the conversion be made in the commodity component of the rate and that it be based on a system average heating value of 1062 Btu per cubic foot.

During the course of the hearings, San Diego's witness urged that were the Commission to order the conversion at this time and not accept the agreement between applicant and San Diego then both the commodity and demand rates should be converted on the basis of a 1060 Btu level.

The record does not indicate precisely when the average heating value for two consecutive months can be expected to reach 1050 Btu on delivery to San Diego. Since there are seasonal variations in heating value the proposed measure is, in any event, not indicative of average year heating value.

We shall accept applicant's and San Diego's criteria of conversion of all charges to a them basis at 1050 Btu. These rates will, however, be ordered into effect upon the heating value reaching 1050 Btu or less for two consecutive months or as of May 1, 1971 whichever occurs first. This will provide for a definitively scheduled conversion to therm rates and a reasonable revenue impact from any deterioration in heating value.

Summary of Authorized Increases

The table below summarizes, by classes of gas customers, the effects of the authorized rate increases (exclusive of tracking increases subsequent to December 25, 1969) specified in Appendix C to this decision, based on the staff estimated 1970 sales of gas adopted herein:

Summary of Authorized Increases
Test Year 1970

Class of Service	Adopted Sales MMcf	Adopted Revenue at 12-25-69 Rates	Authorized Increase Amount	Authorized Increase Per-cent	Authorized Increase Per Mcf	Avg. Rev. Per Mcf After Increase
General Service	144,682	M$136,114	M$15,410	11.32	10.65¢	104.73¢
Firm Industrial	12,339	7,675	479	6.24	3.88	66.08
Subtotal	157,021	143,789	15,889	11.05	10.12	101.69
Gas Engine	1,645	797	88	11.04	5.35	53.80
Regular Interr.	49,471	19,910	1,910	9.59	3.86	44.11
Steam Elec. Plnt.	153,586	49,247	3,342	6.79	2.18	34.24
Wholesale	86,838	32,453	3,223	9.93	3.71	41.08
Subtotal	448,561	246,196	24,452	9.93	5.45	60.34
Spec. Steam Plnt.	8,382	2,989	-	-	-	-
Other Gas Revenue	-	1,001	-	-	-	-
Total	456,943	250,186				

Contingent Offset Charges

In Phase I, by Decision No. 77100, applicant was authorized to place into effect in proper sequence rates increased to include as offset charges the April 13, 1970, El Paso basic increase in Docket No. RP70-11 and the June 16, 1970, Transwestern basic increase in Docket No. RP70-19. 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 for El Paso and Transwestern.

As mentioned previously, the rate spread in Phase II concerns both the El Paso and Transwestern basic increases and the general rate increase sought in Phase II. Neither applicant nor the staff, however, in their respective rate designs segregated increases as between cost of gas increases and other(general cost)increases.

Under these circumstances we are confronted by the question as to whether there is a more appropriate basis for determining contingent offset charges in view of the record developed in Phase II.

In our view, the contingent offset charges established by our decision in Phase I should not be altered at this time. From a cost behaviorial standpoint, reasonable relationships appear to be maintained among the various classes of service by relating cost of gas increases, or decreases, to a uniform cents per Mcf distribution with some adjustment for levels of service to customer classes subject to curtailment.

For similar reasons, we do not deem it appropriate that tracking increases which may be filed under the advice letter procedure established in Phase I, but occurring after our decision herein, be spread to classes of service on a uniform percentage basis. In our opinion, proper rate relationships among the various classes of service are being established by this decision, and from a cost behaviorial standpoint, it is not appropriate to spread cost of gas increases on a uniform percentage basis. We will not change the spread authorized in Phase I applicable to tracking increases.

Findings

1. In Phase I, by Decision No. 77100, applicant was authorized to increase its gas rates to offset higher costs occasioned by increases in the rates of El Paso and Transwestern, the so-called basic increases in FPC Docket Nos. RP70-11 and RP70-19. Such increases in rates are expected to yield additional annual gross revenues of $16,704,000, as compared with applicant's rate levels in effect on December 25, 1969, based on test year 1970.

2. In Phase II, applicant seeks authorization to make effective basic rates which will produce revenues which exceed those from rates in effect on December 25, 1969, by $28,511,000 annually. The basic increases, but not the tracking increases, authorized in Phase I are included in this amount. Thus, the net increase in gross revenues sought by applicant in Phase II is $11,807,000.

3. Under the rates and charges for its gas service in effect December 25, 1969, applicant's earnings during the 1970 test year produce a rate of return of 4.01 percent on a rate base of $274,078,000. The adopted estimates of operating revenues, operating expenses, and rate base, previously discussed herein, yielding this earnings level depend in part on the test year operational results of applicant's affiliate, PLSC. The test year operational results of PLSC, which we find reasonable and adopt, are set forth in Appendix B attached to this decision.

4. A reasonable range for the rate of return for applicant and the Pacific Lighting Utility System in these proceedings is 7.65 to 7.85 percent. Such a range of return should produce

returns on common equity attributable to the Pacific Lighting Utility System of 11.42 percent to 11.95 percent.

5. The level of return to be adopted as reasonable for purposes of authorizing rates herein should be 7.75 percent on applicant's rate base of $274,078,000 in the test year.

6. Applicant is entitled to increased net revenues in the amount of $10,261,000 an amount sufficient to raise its 1970 test year rate of return to the 7.75 percent level. An increase of $24,452,000 in gross revenues, based upon the test year, is justified. Accordingly, applicant should be authorized to increase its December 25, 1969, gas rate levels to the extent indicated in Appendix C hereto (exclusive of subsequent tracking increases) so as to yield additional annual gross revenues in the amount of $24,452,000 based upon the test year.

7. All classes of service should bear a portion of the required revenue increase of $24,452,000.

8. The rates authorized by this Commission, as set forth in Appendix C hereto, reflect a fair and reasonable spread of the authorized increase in gross revenues of $24,452,000 to the various classes of service.

9. Applicant's proposed revisions in the rate form and design of the general service schedules, including establishment of Schedule G-10, as set forth herein and in greater detail in Exhibit No. 9.2, are reasonable and should be authorized. Similar proposals concerning the schedules for firm industrial service and gas engine service appear reasonable and also should be authorized.

10. Conversion of the rates in Wholesale Schedule G-60 to a therm basis as set forth herein is reasonable.

11. Neither the contingent offset charges nor the spread of the so-called tracking increases established by our decision in Phase I of these proceedings should be altered at this time.

12. The rates authorized by this Commission, as set forth in Appendix C hereto, are fair, just and reasonable.

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

1. The Phase II portion of 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. All motions consistent with these findings and conclusions should be granted and those inconsistent therewith should be denied.

5. For the period 1971-1973 quarterly reports should be filed with the Commission describing new research and development projects applicant will undertake and progress being made on projects underway.

O R D E R

IT IS ORDERED that:

1. Applicant Southern Counties Gas Company of California (now, after the merger, 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 C 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. Applicant shall file with this Commission, within thirty days after each calendar quarter of the years 1971 through 1973, a quarterly report describing new research and development projects in which it plans to participate, and summarizing progress on the projects underway.

3. The Phase II portion of the application herein, in all other respects, is denied.

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 ten days after the date hereof.

Dated at San Francisco, California, this 24th day of NOVEMBER, 1970.

J. P. Vukasin Jr.
Chairman

[illegible]

William Symons Jr.

[illegible]

Vernon L. Sturgeon
Commissioners

Appendix A

List of Appearances

FOR APPLICANT

John Ormasa, K. R. Edsall, C. Robert Salter, and Rufus W. McKinney, for Southern California Gas Company, Southern Counties Gas Company of California and Pacific Lighting Service Company.

FOR PROTESTANT

Lorenzo Foster, for Los Angeles Neighborhood Legal Services and Mrs. Shirley Goldinger, for Association of California Consumers.

FOR INTERESTED PARTIES

Chickering & Gregory by Sherman Chickering, C. Hayden Ames and Donald J. Richardson, Jr., for San Diego Gas & Electric Company; Stanley Jewell, Esq., Vice President and General Attorney, for San Diego Gas & Electric Company; Rollin E. Woodbury, Harry W. Sturges, Jr., William E. Marx and William Seaman, for Southern California Edison Company; Roger Arnebergh, City Attorney, by Charles E. Mattson, Deputy City Attorney, for City of Los Angeles; A. H. Driscoll, Assistant City Attorney, and J. O. Russell, for City of Los Angeles, Department of Water & Power; John W. Witt, City Attorney, and Curtis M. Fitzpatrick, Chief Deputy City Attorney, for City of San Diego; Captain James Pleyte, Attorney at law, for Department of Defense and other interested federal agencies; John J. O'Connor, Attorney at law, for City of Glendale; Stuart R. Foutz, Attorney at law, for Southwest Division, Naval Facilities Engineering Command; J. K. Stanners and Charles S. Doskow, for Thatcher Glass Manufacturing Company, division of Dart Industries, Inc.; K. L. Parker, for City of Glendale; Broebeck, Phleger & Harrison by Gordon E. Davis, for California Manufacturers Association; Robert W. Russell, Chief Engineer and General Manager, for Department of Public Utilities & Transportation, City of Los Angeles; J. Randolph Elliott, Attorney at law, for California Portland Cement Company; Henry F. Lippitt, 2d, Attorney at law, for California Gas Producers Association;

APPENDIX A (Cont'd)

List of Appearances

FOR INTERESTED PARTIES (Cont'd)

Louis Possner, Bureau of Franchises and Public Utilities, Edward C. Wright, Long Beach Gas Department, Harold A. Lingle, Deputy City Attorney, L. L. Bendinger and Roy A. Wehe, Consulting Engineer, for City of Long Beach; Knapp, Gill, Hibbert & Stevens by Karl K. Roos, and Arthur H. Sulliger, for Valley Nitrogen Products, Inc.; J. Anthony Bryan, for City of Glendale; Robert F. Smith and Walter C. Leist, for Union Carbide Corporation; H. Gary Jeffries, Deputy City Attorney, for City of Pasadena; Kenneth N. Lounsbery, for City of San Diego; William L. Knecht, for California Farm Bureau Federation.

FOR THE COMMISSION STAFF

Elinore C. Morgan and Gary L. Hall, Counsels; Bruno A. Davis and Raymond E. Heytens.

A. 51568 - NW/gf *

Appendix B

Pacific Lighting Service Company

SUMMARY OF EARNINGS

Test Year 1970 - Cost of Service Tariff

Item	At 4.50% Rate of Return1/	At 7.75% Rate of Return2/
	(Dollars in	Thousands)
Operating Revenues		
Gas Sales	$193,249	$200,012
Other	2,249	2,249
Total	195,498	202,261
Operating Expenses		
Production	177,345	177,345
Storage	1,328	1,328
Transmission	3,455	3,455
Distribution	-	-
Customer Accounts	-	-
Sales	-	-
Administrative & Gen.	2,577	2,584
Subtotal	184,705	184,712
Depreciation	3,522	3,522
Taxes	2,747	6,236
Total Oper. Exp.	190,947	194,470
Net Revenue	4,524	7,791
Rate Base	100,535	100,535
Rate of Return	4.50%	7.75%

1/ Weighted average rate of return of Southern California Gas Company and Southern Counties Gas Company of California at gas rates in effect 12-25-69.

2/ Weighted average rate of return of Southern California Gas Company and Southern Counties Gas Company of California at gas rates authorized by Decision No. 77975 in Application No. 51567 and Decision No. 77976 in Application No. 51568.

A-51568

RATES - SOUTHERN COUNTIES GAS COMPANY OF CALIFORNIA

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

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

PRELIMINARY STATEMENT

Delete the text of the present Preliminary Statement under "(2)DESCRIPTION OF SERVICE", and insert thereunder the following:

Service is rendered under General, Optional Residential, Military, Multiple Dwelling, Street and Outdoor Lighting, Firm Industrial, Gas Engine, Interruptible Industrial, Utility Steam Electric Generating Station and Cement Plant Retail, and Wholesale Rate Schedules. All applicants for service will be served in accordance with the rates, conditions, and rules set forth in these tariff schedules.

The rates specified in these schedules apply only to the use of such gas as is regularly furnished by the company in the locality in which the premises to be served are situated, the gas supplied to be of the heating quality and pressure as stated in Rule No. 2.

PART I - RATES AUTHORIZED, EXCLUDING TRACKING INCREASES SUBSEQUENT TO DECEMBER 25, 1969.

GENERAL NATURAL GAS SERVICE

	Per Meter Per Month						
	G-11	G-12	G-13	G-14	G-15	G-16	G-17
RATES							
Commodity Charge							
First 2 TU or less	$2.75*	$2.75*	$2.80*	$2.85*	$2.90*	$2.95*	$3.00*
Next 18 TU, per TU	8.435¢	8.635¢	8.834¢	9.035¢	9.235¢	10.185¢	12.585¢
Next 980 TU, per TU	7.185	7.315	7.405	7.505	7.616	7.966	8.426
Over 1000 TU, per TU	6.935	6.935	6.935	6.935	6.935	6.935	6.935

* For "space heating only" customers a monthly minimum charge of twice this amount applies during the November through April billing periods. For the May through October billing periods the rate for the next 18 thermal units will apply also to the first 2 thermal units and except for closing bills, usage will be accumulated to at least 11 thermal units before billing. The term "space heating only" applies to customers who are using gas primarily for space heating for human comfort, as determined by survey or under the presumption that customers who use less than 11 thermal units per month during each of the regular billing periods ending in August and September are using gas primarily for space heating for human comfort.

GENERAL NATURAL GAS SERVICE - (Continued)

RATES - (continued)

	Per Meter Per Month						
	G-11	G-12	G-13	G-14	G-15	G-16	G-17
Minimum Charge							
All customers except "space heating only"	$2.75	$2.75	$2.80	$2.85	$2.90	$2.95	$3.00
"Space heating only" cust.							
November thru April	5.50	5.50	5.60	5.70	5.80	5.90	6.00
May thru October	None	None	None	None	None	None	None

SPECIAL CONDITIONS

Delete Special Conditions 1, 2 and 3.

OPTIONAL RESIDENTIAL FIRM NATURAL GAS SERVICE

RATES

	Per Meter Per Month G-10
Commodity Charge:	
In rate areas where Schedule G-11,G-12,G-13,G-14 or G-15 applies:	
First 2 thermal units or less	$ 1.80
Over 2 thermal units, per unit	11.372¢
In the rate area where Schedule G-16 applies:	
First 2 thermal units or less	$ 2.00
Over 2 thermal units, per unit	11.372¢
In the rate area where Schedule G-17 applies:	
First 2 thermal units or less	$ 2.05
Over 2 thermal units, per unit	13.372¢

Minimum Charge: The minimum charge is the charge for the first 2 thermal units or less.

APPLICABILITY

Applicable to firm natural gas service for use in family dwelling units.

SPECIAL CONDITIONS

1. Customers served under this schedule have priority in the use of gas over customers served under gas engine and industrial schedules at times when there is insufficient gas to supply the demand of all customers.

2. A customer may transfer from this schedule to another firm natural gas service schedule at any time but, having done so, may not transfer back to Schedule G-10 for a period of 12 months.

Schedule G-30 to be redesignated as G-31

MULTI-FAMILY AND MILITARY NATURAL GAS SERVICE

RATES	Per Meter Per Month G-20	Per Month G-20
Commodity Charge:		
First 20,000 thermal units, per unit	6.528¢	
Over 20,000 thermal units, per unit	6.028	
Minimum Charge		$200.00

FIRM INDUSTRIAL NATURAL GAS SERVICE

RATES	Per Meter Per Month G-40
Commodity Charge:	
First 1,000 thermal units, per unit	7.156¢
Next 2,000 thermal units, per unit	6.396
Next 17,000 thermal units, per unit	5.956
Over 20,000 thermal units, per unit	5.536
Minimum Charge: To be made cumulative only when total billing exceeds $360.00 per meter at any time during the contract year.	$30.00

SPECIAL RATES FOR AIR CONDITIONING USAGE

SCHEDULES G-11 THROUGH G-17, G-20 and G-40

	Per Meter Per Month May through October
First 100 thermal units, per unit	5.824¢
Next 150 thermal units, per unit	5.084
Next 250 thermal units, per unit	4.634
Next 1,500 thermal units, per unit	4.264
Next 8,000 thermal units, per unit	3.924
Over 10,000 thermal units, per unit	3.824

Upon application, customers who have installed and are using gas air conditioning equipment will be billed under the air conditioning rate for monthly consumption up to 53 thermal units per rated full ton of such equipment, provided that the first 2 thermal units of the total monthly consumption for G-11 through G-17 customers shall be billed at the rate applicable to regular usage.

GAS ENGINE NATURAL GAS SERVICE

RATES

	Per Meter Per Month G-46
Commodity Charge:	
First 1,000 thermal units, per unit	6.109¢
Next 4,000 thermal units, per unit	5.539
Next 5,000 thermal units, per unit	5.019
Over 10,000 thermal units, per unit	4.729
Minimum Charge:	
Initial meter installation	$7.00

To be made cumulative only when total billing exceeds $84.00 per meter at any time during the contract year.

APPLICABILITY

Applicable to firm service for stationary internal combustion engines only.

INTERRUPTIBLE NATURAL GAS SERVICE

SCHEDULE NO. G-51

RATES

	Per Meter Per Month G-51
Commodity Charge:	
First 2,000 thermal units, per unit	5.494¢
Next 8,000 thermal units, per unit	5.064
Next 20,000 thermal units, per unit	4.874
Next 30,000 thermal units, per unit	4.693
Next 40,000 thermal units, per unit	4.513
Next 100,000 thermal units, per unit	4.373
Over 200,000 thermal units, per unit	4.263
Special Rate for Air Conditioning Usage May through October:	
First 2,000 thermal units, per unit	4.090¢
Next 8,000 thermal units, per unit	3.720
Over 10,000 thermal units, per unit	3.630

Upon application, customers who have installed and are using gas air conditioning equipment will be billed under the air conditioning rate for monthly consumption up to 53 thermal units per rated full ton of such equipment.

Minimum Charge:	
Per Meter Per Month	$100.00

To be made cumulative only when total billing exceeds $1,200.00 per meter at any time during the contract year.

SCHEDULE NO. G-53V

RATES

	Per Meter Per Month G-53V
Commodity Charge:	
First 440,000 therms per therm	3.8426¢
Next 660,000 therms, per therm	3.5726
Over 1,100,000 therms, per therm	3.4326
Special Rate for Air Conditioning Usage May through October:	
First 11,000 therms, per therm	3.5627¢
Over 11,000 therms, per therm	3.4227

Upon application, customers who have installed and are using gas air conditioning equipment will be billed for the first portion of the total monthly consumption during billing periods ending in the months of May to October, inclusive, up to 55 therms per rated full ton of such equipment.

UTILITY STEAM-ELECTRIC GENERATING STATION AND CEMENT PLANT RETAIL NATURAL GAS SERVICE

SCHEDULE NO. G-54A

RATES

	Base Rates Per Mcf	
	Winter	Summer
Commodity Charge:		
All gas	38.320¢	
First 10 Mcf per month per Mcf of contract volumetric rate		40.920¢
Next 10 Mcf per month per Mcf of contract volumetric rate		37.920
Next 10 Mcf per month per Mcf of contract volumetric rate		34.920
Excess over above volumes		37.420

OPTIONAL GUARANTEED LONG-TERM ASSURED ANNUAL SUPPLY NATURAL GAS SERVICE FOR UTILITY STEAM-ELECTRIC GENERATING STATIONS

SCHEDULE NO. G-55A

RATES

	Effective Rates Per Therm	
	"A" Rates	"S" Rates
Commodity Charge:		
Summer Period:		
First 5,400,000 therms per month	3.2643¢	3.4253¢
Over 5,400,000 therms per month	3.2643	3.3613
Winter Period:		
Basic gas	3.2643	3.4253
Excess gas	3.0593	3.0593

NATURAL GAS FUEL FOR UTILITY ELECTRIC GENERATION

SCHEDULE NO. G-58A

RATE

The rate for all gas supplied under this schedule is 32.243¢ per million Btu.

WHOLESALE NATURAL GAS SERVICE

SCHEDULE NO. G-61

RATES

Monthly Facility Charge:	$97,500
Monthly Demand Charge:	
Per Mcf of contract daily maximum demand	$3.8092
Commodity Charge:	
Per Mcf of monthly delivery	28.083¢

PART II - RATES AUTHORIZED, INCLUDING TRACKING INCREASES THROUGH JULY 2, 1970

GENERAL NATURAL GAS SERVICE

RATES	Per Meter Per Month						
	G-11	G-12	G-13	G-14	G-15	G-16	G-17
Commodity Charge:							
First 2 TU or less	$2.75282*	$2.75282*	$2.80282*	$2.85282*	$2.90282*	$2.95282*	$3.00282*
Next 18 TU, per TU	8.576¢	8.776¢	8.975¢	9.176¢	9.376¢	10.326¢	12.726¢
Next 980 TU, per TU	7.326	7.456	7.546	7.646	7.757	8.107	8.567
Over 1000 TU per TU	7.076	7.076	7.076	7.076	7.076	7.076	7.076

*For "space heating only" customers a monthly minimum charge of twice this amount applies during the November through April billing periods. For the May through October billing periods the rate for the next 18 thermal units will apply also to the first 2 thermal units and, except for closing bills, usage will be accumulated to at least 11 thermal units before billing. The term "space heating only" applies to customers who are using gas primarily for space heating for human comfort, as determined by survey or under the presumption that customers who use less than 11 thermal units per month during each of the regular billing periods ending in August and September are using gas primarily for space heating for human comfort.

Minimum Charge:	Per Meter Per Month						
	G-11	G-12	G-13	G-14	G-15	G-16	G-17
All cust. except "space heating only"	$2.75	$2.75	$2.80	$2.85	$2.90	$2.95	$3.00
"Space heating only" customers:							
November thru April	5.51	5.51	5.61	5.71	5.81	5.91	6.01
May through Oct.	None	None	None	None	None	None	None

SPECIAL CONDITIONS

Delete Special Conditions 1, 2 and 3.

OPTIONAL RESIDENTIAL FIRM NATURAL GAS SERVICE

RATES	Per Meter Per Month G-10
Commodity Charge:	
In rate areas where Schedule G-11, G-12, G-13, G-14 or G-15 applies:	
First 2 thermal units or less	$ 1.80282
Over 2 thermal units, per unit	11.513¢
In the rate area where Schedule G-16 applies:	
First 2 thermal units or less	$ 2.00282
Over 2 thermal units, per unit	11.513¢
In the rate area where Schedule G-17 applies:	
First 2 thermal units or less	$ 2.05282
Over 2 thermal units, per unit	13.513¢

Minimum Charge: The minimum charge is the charge for the first 2 thermal units or less.

OPTIONAL RESIDENTIAL FIRM NATURAL GAS SERVICE (continued)

APPLICABILITY

Applicable to firm natural gas service for use in family dwelling units.

SPECIAL CONDITIONS

1. Customers served under this schedule have priority in the use of gas over customer served under gas engine and industrial schedules at times when there is insufficient gas to supply the demand of all customers.

2. A customer may transfer from this schedule to another firm natural gas service schedule at any time but, having done so, may not transfer back to Schedule G-10 for a period of 12 months.

3. Contingent Offset Charges Related to F.P.C. Dockets
The rates include offset charges as shown below related to increases and decreases in cost of gas from El Paso Natural Gas Company and Pacific Lighting Service Company (including California gas) as a result of F.P.C. Dockets Nos. RP 69-6, RP 69-20 and RP 70-11 of El Paso Natural Gas Company and RP 69-27 and RP 70-19 of Transwestern Pipeline Company.

F.P.C. Docket	Offset Charge
RP 69-6	0.333¢ per thermal unit
RP 69-20	0.147¢ per thermal unit
RP 69-27	0.131¢ per thermal unit
RP 70-11	0.306¢ per thermal unit
RP 70-19	0.309¢ per thermal unit

To the extent that the F.P.C. in these dockets orders reduction in the rates for El Paso or Transwestern gas with the resulting effect on cost of gas from the above-noted sources, the offsets will be reduced related to the reduction in cost of gas from these sources.

4. Refunds of Contingent Offset Charges Related to F.P.C. Dockets Nos. RP 69-6, RP 69-20, RP 69-27, RP 70-11 and RP 70-19.

Refunds received from El Paso Natural Gas Company and Pacific Lighting Service Company as related to these dockets will be made to various customer classes in proportion to the contingent offset charges collected during the periods to which the refunds apply.

MULTI-FAMILY AND MILITARY NATURAL GAS SERVICE

RATES	Per Meter Per Month G-20	Per Month G-20
Commodity Charge:		
First 20,000 thermal units, per unit	6.669¢	
Over 20,000 thermal units, per unit	6.169	
Minimum Charge		$200.00

Schedule G-30 to be redesignated as G-31

FIRM INDUSTRIAL NATURAL GAS SERVICE

RATES

	Per Meter Per Month G-40
Commodity Charge	
First 1,000 thermal units, per unit	7.297¢
Next 2,000 thermal units, per unit	6.537
Next 17,000 thermal units, per unit	6.097
Over 20,000 thermal units, per unit	5.677
Minimum Charge:	$30.00

To be made cumulative only when total billing exceeds $360.00 per meter at any time during the contract year.

SPECIAL RATES FOR AIR CONDITIONING USAGE

SCHEDULES G-11 THROUGH G-17, G-20 and G-40

	Per Meter Per Month May through October
First 100 thermal units, per unit	5.995¢
Next 150 thermal units, per unit	5.225
Next 250 thermal units, per unit	4.775
Next 1,500 thermal units, per unit	4.405
Next 8,000 thermal units, per unit	4.065
Over 10,000 thermal units, per unit	3.965

Upon application, customers who have installed and are using gas air conditioning equipment will be billed under the air conditioning rate for monthly consumption - up to 53 thermal units per rated full ton of such equipment, provided that the first 2 thermal units of the total monthly consumption for G-11 through G-17 customers shall be billed at the rate applicable to regular usage.

GAS ENGINE NATURAL GAS SERVICE

RATES

	Per Meter Per Month G-46
Commodity Charge:	
First 1,000 thermal units, per unit	6.193¢
Next 4,000 thermal units, per unit	5.623
Next 5,000 thermal units, per unit	5.103
Over 10,000 thermal units, per unit	4.813
Minimum Charge:	
Initial meter installation	$7.00

To be made cumulative only when total billing exceeds $84.00 per meter at any time during the contract year.

APPLICABILITY

Applicable to firm service for stationary internal combustion engines only.

INTERRUPTIBLE NATURAL GAS SERVICE

SCHEDULE NO. G-51

RATES

	Per Meter Per Month G-51
Commodity Charge:	
First 2,000 thermal units, per unit	5.578¢
Next 8,000 thermal units, per unit	5.148
Next 20,000 thermal units, per unit	4.958
Next 30,000 thermal units, per unit	4.777
Next 40,000 thermal units, per unit	4.597
Next 100,000 thermal units, per unit	4.457
Over 200,000 thermal units, per unit	4.347
Special Rate for Air Conditioning Usage May through October:	
First 2,000 thermal units, per unit	4.174¢
Next 8,000 thermal units, per unit	3.804
Over 10,000 thermal units, per unit	3.714

Upon application, customers who have installed and are using gas air conditioning equipment will be billed under the air conditioning rate for monthly consumption up to 53 thermal units per rated full ton of such equipment.

Minimum Charge:

Per Meter Per Month	$100.00

To be made cumulative only when total billing exceeds $1,200.00 per meter at any time during the contract year.

SCHEDULE NO. G-53V

RATES

	Per Meter Per Month G-53V
Commodity Charge:	
First 440,000 therms, per therm	3.9270¢
Next 660,000 therms, per therm	3.6570
Over 1,100,000 therms, per therm	3.5170
Special Rate for Air Conditioning Usage May through October:	
First 11,000 therms, per therm	3.6471¢
Over 11,000 therms, per therm	3.5071

Upon application, customers who have installed and are using gas air conditioning equipment will be billed for the first portion of the total monthly consumption during billing periods ending in the months of May to October, inclusive, up to 55 therms per rated full ton of such equipment.

UTILITY STEAM-ELECTRIC GENERATING STATION AND CEMENT PLANT RETAIL NATURAL GAS SERVICE

SCHEDULE NO. G-54A

RATES

	Base Rates Per Mcf	
	Winter	Summer
Commodity Charge:		
All gas	38.629¢	
First 10 Mcf per month per Mcf of contract volumetric rate		41.229¢
Next 10 Mcf per month per Mcf of contract volumetric rate		38.229
Next 10 Mcf per month per Mcf of contract volumetric rate		35.229
Excess over above volumes		37.729

OPTIONAL GUARANTEED LONG-TERM ASSURED ANNUAL SUPPLY NATURAL GAS SERVICE FOR UTILITY STEAM-ELECTRIC GENERATING STATIONS

SCHEDULE NO. G-55A

RATES

	Effective Rates Per Therm	
	"A" Rates	"S" Rates
Commodity Charge:		
Summer Period:		
First 5,400,000 therms per month	3.2923¢	3.4533¢
Over 5,400,000 therms per month	3.2923	3.3893
Winter Period:		
Basic gas	3.2923	3.4533
Excess gas	3.0873	3.0873

NATURAL GAS FUEL FOR UTILITY ELECTRIC GENERATION

SCHEDULE NO. G-58A

RATE

The rate for all gas supplied under this schedule is 32.523¢ per million Btu.

WHOLESALE NATURAL GAS SERVICE

SCHEDULE NO. G-61

RATES

Monthly Facility Charge:	$97,500
Monthly Demand Charge:	
Per Mcf of contract daily maximum demand	$3.8092
Commodity Charge:	
Per Mcf of monthly delivery	28.978¢