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ORIGINAL

Decision No. 83160

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, and (b) For Authority to Include a Purchased Gas Adjustment Provision in Its Tariffs.

Application No. 53797
(Filed January 19, 1973)

(List of Appearances in Appendix A)

OPINION ON PHASE I

Southern California Gas Company's (SoCal) application seeks authority for a general increase of $53,151,000 in its gas rates, designed by SoCal to yield an 8.5 percent rate of return on its rate base, based upon a summary of earnings for test year 1974 contained in Exhibit D attached to the application. During the course of the hearings SoCal made certain changes in its estimated operating results which would reduce its revenue requirements by approximately $2,392,000 including an alternate treatment for gas exploration and development activities (GEDA) authorized in Decision No. 81898 dated September 25, 1973; a reduction of administrative and general expenses for dues and donations, and a reduction of income tax expenses related to income for discharge of indebtedness (IDI). SoCal requests consideration of later data requiring increased revenues to offset expenses higher than originally estimated, namely:

(a) $89,000 for increases in social security taxes;

(b) Sales tax increases, $640,000 on an annualized basis, $480,000 for 9 months beginning on April 1, 1974;

(c) Increased postal rates, $900,000 for full year 1974 (the increases were deferred to March 2, 1974); and

(d) Increased research and development expenses of $1,000,000.

SoCal also requests the Commission to consider (a) its revised estimate of net plant budget expenditures of approximately $6,300,000 above its original estimate for the consolidated operations of SoCal and its utility affiliate Pacific Lighting Service Company (PLS), and (b) that reductions in its 1973-1974 ad valorem taxes, which would reduce its April 1974 payments by $740,000 might be offset by a greater amount, over its original estimate, for its December 1974 payments.

The 8.5 percent rate of return being sought by SoCal is the same as it requested in Application No. 52696, based on a 1972 test year. Decision No. 80430 in that proceeding authorized a rate of return of 8.0 percent.

SoCal also requests authority to incorporate a purchased gas adjustment clause (PGA) in its tariff schedules to permit it to promptly reflect in its rates all changes in the cost of purchased gas. SoCal is the only purchaser of gas from PLS. These gas sales are made under a cost of service tariff approved by this Commission. All of the expenses and return for PLS are included as a part of SoCal's revenue requirements.

SoCal states that:

(a) Growth in number of customers and growth in firm use per meter are occuring at slower rates than have been experienced in the past and that these slower growth rates are expected to continue;

(b) A shortage in gas supplies caused by curtailment of deliveries to SoCal from its out-of-state suppliers and a sharp decline in gas availability from California suppliers, including federal offshore suppliers, has resulted in lower delivery levels to SoCal's interruptible customers;

(c) Its operating and maintenance costs are continuing to increase;

(d) The wage rates being paid are higher than those reflected in Decision No. 80430 and costs of pensions and employee benefits are increasing;

(e) The cost of materials and supplies used in the operation of its business is increasing;

(f) Programs to meet new safety and health standards and environmental restrictions will result in higher operating and maintenance expenses;

(g) The development of its underground storage facilities has been significantly accelerated to meet increased requirements for load balancing to meet its firm requirements because of the above-mentioned decline in gas supplies and that this expansion requires large amounts of additional capital and results in significantly higher operating expenses;

(h) $175,000,000 of new capital from external sources is needed in 1973 and 1974, $95,000,000 of which would be from new debt and $80,000,000 from new common stock to finance the growing plant requirements of both SoCal and PLS. A rate of return of 8.5 percent on rate base is needed to enable these companies to raise new debt and equity capital on satisfactory terms; and

(i) Its costs of imbedded long-term debt will increase from 5.92 percent at the end of 1972 to 6.24 percent at the end of 1974. The 8.5 percent requested rate of return should enable SoCal and PLS to meet their financial requirements, especially reasonable interest coverage for their bonds, and to retain satisfactory ratings on their debt securities.

SoCal presently utilizes two different procedures to offset purchased gas costs increases. SoCal is authorized to increase its rates following the advice letter procedure where the increase results from a tracking increase, an increase put into effect by either of its out-of-state pipeline company suppliers (El Paso Natural Gas Company (El Paso) and Transwestern

Pipeline Company (Transwestern)) to reflect an increase in the prices El Paso or Transwestern is required to pay gas producers. SoCal has to file an application to offset increased gas costs where El Paso or Transwestern seeks an increase other than for tracking, for increases in gas costs from its California suppliers (not related to tracking), and for increases for California federal offshore supplies.

A portion of the first day of the hearing in this matter was devoted to taking evidence in such an offset proceeding, Application No. 54065. Decision No. 82042 dated October 24, 1973 authorized SoCal to increase its rates to offset increased gas costs in Federal Power Commission (FPC) Docket No. RP73-104, subject to refund and reduction if lower rates were ordered by the FPC. The increase was also subject to refund if there was any excess of charges over increases in expenses, or if the end of year temperature adjusted rate of return exceeded the authorized rate(s) of return, up to the amount of the authorized increase.

Similar provisions were contained in Decisions Nos. 81900 dated September 25, 1973 and 82395 dated January 29, 1974 in Application No. 52696. These decisions authorized substitution of the staff estimates of 1974 test year gas purchase and sales volumes for the 1972 test year gas purchase and sales volumes previously used for tracking increases and extension of SoCal's tracking authority from December 31, 1973 to the effective date of this order, which authorizes inclusion of a PGA in SoCal's tariffs.

After notice, 27 days of public hearings were held before Commissioner Symons, Commissioner Moran, and Examiner Levander between August 13, 1973 to November 7, 1973, during which time all parties and the general public were given an opportunity to present testimony and evidence.

Southern California Edison Company (Edison) filed a motion which, interalia, requests the Commission to consider evidence relating to alternate arrangements for deliveries of gas by SoCal to its

G-53-T, G-58, and G-61 customers. The motion to reconsider the basis of allocations to these customers was granted in part in Decisions Nos. 82414, 82657, and 82745. The issues arising out of the Edison motion will not be described in this order except as they relate to our determination of the reasonable level of rates following existing curtailment priorities. The issues related to possible reallocation of gas supplies are being adjudicated in a separate Phase II proceeding.

SoCal, through witnesses, presented testimony and exhibits in support of the requested increases for itself and for PLS. The Commission staff's witnesses presented a comprehensive showing as to all aspects of the proposed rate relief. The city of Los Angeles presented evidence on rate of return. The California Manufacturer's Association (CMA) sponsored evidence on rate spread. The General Services Administration (GSA) presented evidence on Schedule G-20. Other parties to the proceeding state their position on various issues and participated in the cross-examination of witnesses.

SDG&E's proposal that no portion of SoCal's uncollectible expense and unaccounted for gas expense be allocated to SDG&E applied to both Applications Nos. 53797 and 54065. The rationale for our not adopting SDG&E's proposal, contained in Decision No. 82042, also applies to this proceeding.

Public witnesses opposed the gas rate increases because of the adverse inflationary effect such increases would have on charitable institutions, on people with fixed incomes, particularly the elderly and the poor, and because certain businesses, which would have problems in passing through increased gas costs, would have financial problems in absorbing such increases.

On November 7, 1973, Phase I was submitted for decision subject to the receipt of a late-filed exhibit (received on

November 16, 1973). Concurrent opening briefs were filed on December 4, 1973, and concurrent reply briefs were filed on December 21, 1973.

Gas Supply Shortage

Since we issued Decision No. 80430 on August 29, 1972 in SoCal's last general rate increase the national gas supply shortage referred to in that decision has worsened. Adopted gas sales for test year 1972 were 979,086 M^2cf, excluding consideration of a special purchase of 44,000 M^2cf proposed to be delivered to SoCal's retail steam plant customers and to SDG&E for its steam plants at a special contract rate, above regular tariff rates. Recorded 1972 gas sales were 1,015,694 M^2cf.1/ The gas sales volume adopted in this order for test year 1974 is 782,850 M^2cf, a decline of 232,844 M^2cf or 22.9 percent from recorded 1972.

In order to meet its firm peak loads and to meet its seasonal load requirements for 1974 SoCal plans to make a net injection into storage of 39,354 M^2cf.

SoCal's vice president for its System Gas Supply Department testified as to the efforts of applicant, its parent, and its affiliates to obtain new sources of supply to substitute for declining deliveries from El Paso, Transwestern, and the California producers, to add additional volumes of gas to meet increasing firm requirements, and to better meet increasing interruptible loads on the PLS system.

Some of the factors affecting present and future gas supplies available for SoCal's use are:

1/ Including 41,719 M^2cf of special contract gas. SDG&E deferred taking a portion of its special contract gas deliveries until 1973.

(a) Gas producers seek to optimize their profits and weigh the value of oil vs. gas production, often to the detriment of gas production.

(b) Existing gas fields are being depleted.

(c) There is vigorous competition for new gas supplies. El Paso and Transwestern have not obtained sufficient new gas to meet their contracted for deliveries to the PLS system.

(d) Gas exploration and development and coal gassification activities are being carried out by SoCal's affiliates and affiliates of its suppliers to augment gas supplies delivered to existing transmission facilities supplying the PLS system.

(e) New gas supplies are being sought from Alaska and from foreign sources which may involve deliveries by pipeline or as liquified natural gas (LNG) delivered by special tankers.

(f) SoCal is seeking to obtain liquid hydrocarbon feed stocks to operate a synthetic natural gas (SNG) facility to manufacture gas. After feed stocks are obtained SoCal plans to seek certification from this Commission to construct a SNG plant. The plant, which will take about two years to build, may be either a 125 M^{2}cf per day unit costing $45,000,000 to $50,000,000 or a 250 M^{2}cf per day unit costing approximately $75,000,000. The SNG plant is planned to meet SoCal's anticipated near term requirements.

All of these factors point to higher gas costs in the future. The possible effect on average gas costs of prospective Canadian gas imports is discussed under the PGA section in this opinion.

Aliso Storage Field

In Application No. 52696 SoCal and the Commission staff both included the estimated cost of acquisition and 1972 construction in the Aliso storage field in rate base for the full test year 1972. This acquisition was made to meet the peak and seasonal load requirements on the PLS system. The 70,000 M^{2}cf storage capability of Aliso is 2 1/3 times greater than the combined storage capacity of the four other underground storage reservoirs on the PLS system. Since 1972, because of the worsening gas supply situation, PLS has accelerated the development of the Aliso storage field by construction of additional wells, compressors, plant piping, and related facilities so as to be able to inject increased volumes of gas into storage and to increase the rate at which it could withdraw gas from the field. PLS states that it will complete the construction of all facilities related to the Aliso project in late 1974.

The 1974 estimates of SoCal and of the Commission staff include the estimated cost of the 1974 Aliso improvements in rate base as of January 1, 1974 and the estimates of operational expenses, depreciation, and taxes are predicted upon operation of all Aliso facilities for a full year. GSA proposes deletion of Aliso from rate base.

It appears that additional expenditures to meet SoCal's peak and/or seasonal load requirements will be required for the next several years and that the magnitude of the 1974 capital expenditure for the Aliso project, of approximately $23,000,000, is of a similar order of magnitude to the contemplated expenditures needed for meeting peaking and/or seasonal load requirements in the near future. Consequently, it is appropriate to treat the 1974 capital expenditure for the Aliso field on an as-expected basis rather than the pro forma[2/] beginning of year basis used by SoCal and the Commission staff. Our adopted results reflect this treatment which is carried through operation expenses, taxes, and depreciation. Our adopted results include interest during construction at 7.5 percent on the Aliso related plant on an as-expected basis, following PLS' usual practice.

The other issues raised on Phase I proceeding will be discussed under the subjects designated in center headings in the following sequence:

2/ This pro forma treatment does not include capitalized interest during construction (PLS' usual practice), but does include compressor station additions at Adelanto. "As-expected" treatment weights plant as of its operative date.

A. RESULTS OF OPERATION
B. RATE OF RETURN
C. RATE SPREAD
D. PROPOSED PURCHASED GAS ADJUSTMENT CLAUSE

A. RESULTS OF OPERATION

Both applicant and the Commission staff presented results of operation studies of SoCal and PLS for test year 1974 which included all elements related to revenues, including customer growth, increasing firm use per customer, and declining interruptible sales in the revenue mix. The studies reflect the efficiencies of size in operating expenses and facilities. SoCal has the lowest ratio of operating labor per customer of any major gas utility.

During the course of the proceeding, a number of important revisions were made by SoCal and the staff in their respective estimates, some of which were included in Exhibit 46, the comparative results of operation. We will consider applicant's request for further modifications based upon changed information in our adopted results.

Table I on the following page shows the summary of the revised comparative results of operation for SoCal under present rates[3/] in test year 1974 proposed by SoCal and by the Commission staff under existing delivery priorities as set forth in Exhibit 46, and the amounts we will adopt for test year 1974.

3/ Present rates are those effective as of February 15, 1973 reduced by 0.023 cents per therm which are now part of the GEDA charge, and excluding all tracking, offset, and other GEDA changes which have occurred since that date.

TABLE 1

SOUTHERN CALIFORNIA GAS COMPANY

Results of Operation Under February 15, 1973 Rates
Test Year 1974

Item	SoCal	Commission Staff	Utility Exceeds Staff	Adopted
		(Dollars in Thousands)		
Operating Revenues	$648,500	$652,271	$(3,771)	$649,057
Operation and Maint. Exp.				
Production	358,458	358,812	(354)	356,554
Storage	5,890	5,683	207	5,631
Transmission	10,873	10,812	61	10,873
Distribution	55,812	54,189	1,623	54,992
Customer Accounts	30,906	30,854	52	31,515
Sales	12,000	8,430	3,570	8,746
Admin. & General	58,857	55,919	2,938	58,029
Subtotal O&M Expenses	532,796	524,699	8,097	526,340
Wage Increase Adjustment	-	(5,203)	5,203	
Sales Tax Increase	-	-	-	480
Adjusted O&M Expenses	532,796	519,496	13,300	526,820
Taxes				
Taxes Other Than Income	25,849	25,642	207	24,407
Federal Income	5,485	11,992	(6,507)	6,807
State Income	1,858	3,181	(1,323)	2,112
Total Taxes	33,192	40,815	(7,623)	33,326
Depreciation	33,623	33,681	(58)	33,695
Total Oper. Expenses	599,611	593,992	5,619	593,841
Affiliated Int. Adjustment	25	25	0	25
Return	48,914	58,303	9,389	55,241
Rate Base				
Working Cash	19,800	9,670	10,130	11,406
Remainder	812,089	814,194	2,105	814,684
Total	$831,889	$823,864	$8,025	826,090
Rate of Return	5.88%	7.08%	1.20%	6.69%

Operating Revenues

The staff estimate of operating revenue exceeds applicant's estimate by $3,797,000 for gas sales revenues and is $27,000 less for other operating revenues. $3,026,000 of these differences are due primarily to the respective estimates of use per firm meter. The Commission staff used an average of 9,607 more firm customers than SoCal and used a higher number of G-10 customers. The net effect of the latter differences is $771,000.

Estimates as to numbers of customers, usage per firm customer, gas supply, and requirements for all of SoCal's customers were prepared by SoCal and the Commission staff. The Commission staff used later estimated data than SoCal. The record contains later recorded data supporting the staff customer estimate. The staff estimate of numbers of customers and its use of a more recent altitude correction factor are reasonable and are adopted. The staff's later estimate of sales and of the monthly pattern of sales to the city of Long Beach is reasonable and is adopted.

SoCal estimates a firm usage per customer of 135.1 Mcf for test year 1974 as compared to the Commission staff estimate of 137.5 Mcf per customer. The SoCal estimate was developed by projecting the estimated year-end 1972 use per customer at an average growth rate for the 3-year period ending August 1972 and by reflecting average temperature conditions of 1,637 degree days based on a 20-year period ending December 31, 1971. The Commission staff estimate was developed by projecting a straight line least squares trend through temperature adjusted twelve-month moving totals from January 1970 through December 1972 and by reflecting average temperature conditions based on temperatures during the 30-year period ending December 31, 1970 (the basis generally used by major gas utilities).

Temperature adjusted data for early 1973 show higher monthly firm usage per customer than indicated on the staff's trend line. However, we are persuaded by SoCal's argument that the effects of the continuing energy crisis as exemplified by the request of the President of the United States "to lower the thermostat in your home by at least 6 degrees, so that we can achieve a national daytime average of 68 degrees" and the various campaigns undertaken to conserve energy will in fact bring the usage per customer down. SoCal's estimate of usage per firm customer is reasonable and is adopted. Our adoption of SoCal's usage per customer is an end result. The temperature adjusted base period is a tool used for trending usage and for adjusting recorded usage per customer to average conditions. We now require SoCal to report sales information on a recorded and temperature adjusted basis. The record does not persuade us to adopt a 20-year temperature adjusted base for trending firm usage per customer. SoCal may wish to present additional information on this subject in a future rate proceeding but for purposes of reporting temperature adjusted sales it should use a 30-year temperature adjusted base.

The gas sales volumes and the related revenues by class as estimated by SoCal, by the Commission staff, and our adopted sales are shown on the following tabulations. The revenue modification for other revenues reflects the modification of curtailment of interruptible exchange deliveries based upon adopted sales.

Gas Sales by Classes of Service
Test Year 1974

Class of Service	SoCal	Staff	Adopted
	(Sales in M^2cf)		
Firm General Service	442,193	451,555	443,659
Gas Engines	5,699	5,699	5,699
Regular Interruptible	177,164	171,565	177,242
Steam Plants	61,366	58,161	60,077
Wholesale	96,179	96,173	96,173
Total Sales	782,601	783,153	782,850

Revenues by Classes of Service
Test Year 1974

Class of Service	Utility	Staff	Adopted
	(Dollars in Thousands)		
Firm General Service	$485,031	$492,829	$486,172
Gas Engines	3,416	3,416	3,416
Regular Interruptible	88,329	85,527	88,244
Steam Plants	23,127	21,919	22,640
Wholesale	47,120	47,130	47,120
Subtotal	647,023	650,821	647,592
Other Operating Revenues	1,477	1,450	1,465
Total Revenues	648,500	652,271	649,057

Decision No. 82716 dated April 9, 1974 in Applications Nos. 53945, 53946, and 53970 established test year 1974 annual gas requirements for San Diego Gas & Electric Company (SDG&E). It also established annual gas deliveries from SoCal to SDG&E based upon a floor of 80,665 M^2cf, which includes 270 M^2cf to be utilized in LNG storage, 50,890 M^2cf (which includes 1,065.3 M^2cf of peaking gas) to be used directly to meet firm requirements, 8,608 M^2cf to be used to meet retail interruptible sales, and 20,897 M^2cf to be used to meet interdepartmental requirements. Due to the difference between estimated firm usage and adopted firm usage of SoCal's customers, there is a shift of available interruptible supplies by priority blocks. This shift increases SDG&E's regular interruptible deliveries by 88 M^2cf and decreases SoCal's deliveries for SDG&E's interdepartmental usage by 88 M^2cf. The Commission staff's later estimates for regular interruptible and steam plant requirements have been utilized in arriving at the adopted gas sales.

Operating Expenses

SoCal's estimate of $532,796,000 in total operating and maintenance expenses, including administrative and general expenses, is analyzed in detail in the following paragraphs.

Wage and Employee Benefit Adjustments

SoCal's 1974 expense estimate includes a prospective April 1, 1974 wage, salary, and employee benefit increase of 5-1/2 percent on a pro forma full year basis over the comparable April 1, 1973 levels. SoCal characterizes this increase as conservative in light of the increases negotiated in recent years coupled with the ongoing inflation. The wage and salary increases for 1974 total $3,231,000 and the associated fringe benefits total $1,359,000. The Commission staff's wage adjustment of $5,203,000 is based upon the April 1, 1973 salary, wage, and benefit levels, less a $613,000 disallowance to limit the 1973 increase to 5-1/2 percent in accordance with the Phase II guidelines and the spirit of the federal government's Economic Stabilization Program. GSA opposed inclusion of out-of-phase-adjustments in this proceeding. Our adopted results incorporate all of the 1973 wage increase and a 5-1/2 percent wage increase annualized for 1974. The latter amount is subject to reduction if the actual increase is below 5-1/2 percent.

Social Security Taxes, Sales and Use Taxes, and Postage

Changes in sales and use taxes, social security, and in postage rates have been frequent in recent years. Consistent with our treatment of the Aliso project our adopted results of operations incorporate these increases for the period they are anticipated to be in effect in the test year. The breakdown of the amounts attributable to these adjustments are contained in the appropriate sections of this opinion.

Production Expenses

Production expenses account for over 67 percent of SoCal's 1974 estimated O & M expenses, for over 69 percent of the staff estimated O & M expenses, and over 55 percent of their respective total revenues at present rates (see Footnote 3). Production expenses consist mainly of costs of natural gas purchased from

El Paso and from PLS. 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 1974 to determine in turn a substantial part of applicant's production expenses.

The $10,000 use per firm meter and the $178,000 basic expense estimate differences between SoCal and the Commission staff (Table 2, page 26), excluding the PLS purchases, are related to their estimates of gas sales and gas purchases. Adopted total gas purchases by applicant amount to 808,244 M^2cf, of which 10,191 M^2cf is for company use and 15,203 M^2cf for unaccounted for gas (excludes PLS net injection of 39,354 M^2cf and unaccounted for gas of 8 M^2cf).

From our test year 1974 adopted operational results of PLS contained in Table 3 (page 32), the costs of operation which flow to SoCal under the cost-of-service tariff, which includes a fixed rate of return of 8.0 percent, amounts to $142,492,000, which is $2,056,000 lower than estimated by applicant. We find reasonable and adopt production expenses of SoCal, with PLS charges at the existing 8.0 rate of return, in the amount of $356,554,000 for test year 1974, as shown in Table 2 (page 26).

Storage and Transmission Expenses

Applicant's as-expected estimates are developed at the district level by function and by account. These estimates are reviewed through the company's divisional and departmental levels for conformity with company policy and budget goals.

The Commission staff tested applicant's as-expected estimates using five years of recorded data, adjusted to the test year wage levels. to establish straight line trends for each account. The $207,000 and $61,000 differences represent the differences between the trended amounts and the company estimates for 9 of 34 accounts where the trend was below the company estimate. The staff adopted the company's estimate where the trend was above the company estimate. The Commission staff did not justify this selective trending procedure. We adopt SoCal's estimates for transmission expense and for storage expense, less a $259,000 deduction to reflect the as-expected storage operation of the Aliso project.

Distribution Expenses

The Commission staff estimates for customer installations and other operational expenses are $1,122,000 and $319,000 lower than SoCal's estimates because of a changed trend occurring after the 1970 merger of SoCal and Southern Counties Gas Company. The demand for customer installation services fluctuated widely in 1971 and 1972. Operational changes for providing these services are a logical outcome of the merger. The wide fluctuations in customer service demand have a bearing on average costs for providing such services and consequently we will adopt one-half of the adjustments indicated in the staff trends. The adopted amounts for these accounts total $20,520,000, a $721,000 reduction from SoCal's estimate.

The Commission staff's evidence in support of the adjustment of $83,000 for maintenance of distribution structures and improvements is not persuasive. The Commission staff's evidence on trended unit costs for meter repairs, coupled with the inability of applicant to estimate which meter grouping would be repaired prior to completion of their meter survey, justifies our adoption of the staff's $99,000 adjustment for maintenance of meters and house regulators.

Customer Account Expenses

We concur with the staff adjustment of $114,000 for customer accounts supervision based upon past cost ratios between supervisory and non-supervisory labor costs. We adopt the staff's $54,000 higher estimate for meter reading costs which are related to numbers of customers. Uncollectibles are related to adopted revenues.

SoCal's postage expense will increase by $666,000 over estimated postage charges for customer records and collections.

Sales Expenses

SoCal estimated its 1974 sales expenses at $12,000,000 for advertising, promotion, and customer information. The Commission staff estimate is $3,570,000 lower, consisting primarily of deletions of all expenses related to residential appliances ($1,505,000), packaged air conditioning ($639,000), and food service ($665,000); of the elimination of $600,000 of $800,000 for advertising expenses in support of manufacturers; and deletion of related supervisory salaries and expenses ($130,000).

SoCal contends that all of these expenditures are needed to carry out its objectives and emphasizes that the level of its advertising expenditures and programs is necessary to counter the heavy expenditures of the electric manufacturers (no breakdown of such electric manufacturers local expenditures in areas competitive with gas appliances was provided), to maintain its share of the market, to encourage manufacturers to continue to turn out gas appliances, and to assist appliance dealers in marketing gas appliances. SoCal's program objectives are:

(a) To accommodate their customers informational needs;

(b) To improve customers efficient and effective use of gas;

(c) To maintain its present market position for gas appliances and equipment and to influence the fuel choice for appliances being installed in new homes and apartments; and

(d) To influence the choice of customers who have committed energy needs.

The Commission staff witness eliminated all expenses for those programs where the 1974 gross revenues attributable to these activities was less than the 1974 expense incurred for the programs because he concluded such programs were not beneficial to the ratepayer. He stated that this monetary criteria was the only one offered by SoCal when he sought to evaluate the programs. Exhibit 44 contains the expense breakdown within each major sales activity by accounts. SoCal's estimates in Account 912 for programs, salary expenses for appliances, packaged air-conditioning, and food service total $2,059,000. The Commission staff adjustment for these items was $2,820,000.

When cross-examined SoCal's witness categorically characterized all of the programs as essential with the following exception:

> "No, I don't consider the packaged air conditioning program as an essential service except the aspect of that which responds to a customer's and a contractor's need to know about the availability of gas air conditioning and what it will do for the customer." (Tr. 708.)

SoCal contends that the expenses for a single year should not be related to revenues for a single year, but to the long term benefits of such expenditures. Exhibit 43 shows the present worth, at 8 percent, of gross revenues anticipated to be derived from all of its programs (over the service lives of the several products) as compared to the 1974 expense. To the extent that the present worth approach is valid, if applied, it should be applied to net revenues to determine benefits to the company. The present worth of net revenues at the authorized rate of return for each of the staff adjusted programs is less than the 1974 expenses.

SoCal's total sales expenses constitute approximately 2.25 percent of its estimated operating expenses. The reasonableness of amounts expended for certain sales marketing activities and for institutional advertising (Account 930) are amounts which the public and their elected representatives frequently take exception to, especially when taken in the context of today's energy shortages. After giving due consideration to the record herein we find that SoCal's $12,000,000 estimate is excessive and that an allowance for SoCal's sales expenses of $8,746,000 is just and reasonable for SoCal's 1974 sales activities. The latter amount includes an allowance for advertising expenses to meet the objectives set out on page 17, lines (a) and (b). SoCal should carefully weigh its priorities and consider the benefits to it and to its customers in setting up various marketing activities.

Administrative and General Expenses

SoCal estimated its administrative and general expenses at $58,857,000 for 1974. The corresponding Commission staff estimate of $55,919,000 includes a $2,143,000 reduction for SoCal's public relations expenditures, a management force reduction of $640,000, and other net reductions of $155,000.

SoCal's rebuttal witness Riffel, its Vice President for Public Relations, testified that the company's public relations effort consists in part of communications programs directed to informing the public of various facts and services relating to the company and to generate mutual understanding between the public and the company; that the thrust of SoCal's institutional advertising was to supply the public with information concerning the natural gas supply situation in Southern California and what SoCal was doing to meet gas supply problems, including reasonable assumptions regarding the probable cost of such programs; and information on the quality and scope of its customer service programs.

Witness Riffel testified that institutional advertising is an arm or tool of public relations and was not synonymous with public relations. Witness Riffel also sought to distinguish institutional advertising and public relations from advertising in connection with California Assembly Resolution HR 56 dated May 22, 1972. This resolution urges the Commission to maintain downward pressure on the over-all level of advertising expenditures; to examine and to require the utility to demonstrate, within guidelines, substantial benefits to the ratepayers for allowed expenses.

Many of the social objectives promoted by SoCal in its public relations programs[4/] appear to be worthy objectives, but GSA correctly points out that Account 426, other income deductions, a nonoperating account, rather than operating accounts, was the proper place for recording such expenditures. The $24,000 for legislative advocacy should be recorded in Subaccount 426.4.

Commission staff witness Penny testified that he equated public relations and institutional advertising because they have the same objective, the enhancement of the corporate image. He did not delve into the purposes of various SoCal programs. His adjustment was based upon increasing a calculated .00054 ratio of institutional advertising to revenue, derived from Decision No. 80878 dated December 19, 1972 in PG&E's gas rate increase Application No. 53118, to .0007348 for all of SoCal's administrative and general public relations activities, including institutional advertising and display shop expenses of $27,000. Witness Penny testified that the thrust of HR 56 and this Commission's Rule 23.1 supports his position.

4/ Public relations expenses are specifically mentioned only in Account 923 of the administrative and general expenses. There is no dispute as to the amount to be included in Account 923.

The staff contends that SoCal's witness Bruncken was originally offered as the witness responsible for justifying the expenses attributable to public relations and institutional advertising; that his prepared testimony contained in Exhibit G is devoid of any mention of either activity much less any justification for these activities; that when given an opportunity to justify these expenses he explains that they were helpful in enhancing the corporate image of applicant; that the Commission staff recognized that the ratepayer received some benefits from such enhancement and made an allowance for that benefit; that the shareholders received the major benefits; and that recognizing the failure of its direct presentation SoCal's rebuttal witness Riffel testified concerning the company's public relations activities.

SoCal has the burden of proof in justifying any portion of its request for a rate increase. It should be explicit in explaining the need for each of its public relations programs and of showing benefits for the ratepayer as well as for the enhancement of its corporate image. The Commission staff estimates should be based upon greater familiarity with specific programs.

After careful consideration of the record we find that just and reasonable test year 1974 expenses for public relations activities and associated employee benefits included in Accounts 920, 921, 926, and 930 are $2,100,000. This amount includes $650,000 for advertising concerning gas safety and information on the gas supply situation. An information program focusing on the cost impact of reduced gas supplies might have a salutary effect on SoCal's energy conservation program.

Witness Penny's estimate reduced regulatory Commission expenses by $135,000 based upon a trending of regulatory expenses incurred. The Commission staff contends that authorization of a PGA would significantly reduce the regulatory burden on applicant and that applicant has not demonstrated the need for expenses related to preparing environmental data statements (EDS). SoCal has subsequently submitted an EDS in a certificate proceeding, Application No. 54671. SoCal's regulatory commission expense estimate is reasonable.

Witness Penny reduced the company's estimate of administrative and general salaries in Account 920 by $640,000 based upon the contention that SoCal did not reflect its planned reduction of 32 management positions in 1974 in its Account 920 estimate.

SoCal states that its management personnel requirements are scattered throughout the operating and maintenance expense accounts and that the reduction in numbers of positions are included in these accounts as well as in Account 920. SoCal did not provide the necessary detail, for the record, as to numbers of management positions spread through the various operating accounts or of the associated expenses. SoCal's Exhibit 48 shows a reduction of two sales management positions as contrasted to its Exhibit 42 which shows no such reduction. Exhibit 21 shows SoCal's estimated full-year management salary increases for 1973 totals $1,753,000. This represents an increase from a 1972 salary base (for positions carried forward into 1973) to a calculated 1973 salary base of $33,626,000. A 1974 annualized increase of 5½ percent from this 1973 base totals $1,849,000. SoCal estimates its 1974 management salary increase at $1,825,000. The expensed portion of SoCal's 1974 management salary increases reflect a $370,000 expense decrease from the 1973 salary base level.

Our adopted administrative and general expenses reflect a $270,000 net reduction for management salaries, the difference between the Commission staff's $640,000 adjustment and the reduction contained in SoCal's estimates.

We have increased administrative and general expenses by $83,000 to reflect increased postage costs not in effect when SoCal prepared its application. There is no question of the need for SoCal to pay increased postage rates, increased sales taxes, and increased social security taxes to carry out its day-to-day activities.

In the area of SoCal's research and development (R&D) activities we enter into a discretionary type of activity. SoCal sought $2,000,000 for test year 1974 R&D activities. The nature of the R&D activities and the reasons for them, to carry out energy conservation and pollution abatement activities, were explored on the record. SoCal's testimony was that five years ago the company was trying to sell more gas but that at this time the company was trying to get themselves and their customers in a position to survive an energy supply crisis that is growing constantly and the end of which is not in sight; that SoCal's revenue requirement could be increased by reason of having to spread its fixed costs over smaller volumes of gas; and that its customers and society would benefit from having more efficient, more pollution-free gas consuming appliances and processes.

The Commission staff adopted SoCal's estimate for R&D expenses of approximately $2,000,000 for test year 1974 (excluding R&D costs for projects to be carried out by affiliates which SoCal included in the PLS rate base). SoCal listed the increased estimates for its 1974 R&D program on the record but it did not seek an allowance for the upward revision as part of its basic showing. The increase does not appear in Exhibit 46 which shows the difference between SoCal and the staff. The staff points out that several of the projects are substantial in amount and represent accelerated program developments. One program was for the fuel cell TARGET project. The Commission previously amortized TARGET expenses for ratemaking purposes, but SoCal did not amortize TARGET expenses in this proceeding. The staff contends that, if anything, these expenses should be reduced by appropriate amortization of TARGET and like projects; and that some of the new projects are devoted to developing new uses for natural gas rather than conservation.

GSA opposes inclusion of R&D expenses because they will promote gas usage and also because certain items, if developed, will be used by SoCal and become part of rate base and could be then incorporated in the company's accounts as depreciable assets. GSA suggests that R&D expenditures, if prudent and reasonable, could be put in a deferred account and capitalized or be written off over a reasonable period after the failure of a particular project becomes apparent. GSA contends that under SoCal's treatment ratepayers would be forced to contribute capital by meeting an excessive revenue requirement caused by charging against current income a cost properly relating to future plant and future income.

To the extent that more efficient appliances are developed and marketed and more efficient uses of gas energy are realized, there will be savings of gas. With such savings the requirements for more expensive new sources of gas supply would be lessened, and the average cost of gas in the SoCal gas pool might be reduced. SoCal's interruptible customers would benefit to the extent that the firm gas usage savings were utilized to meet interruptible loads. This is a factor to be considered in rate design. There are benefits to SoCal's customers in authorizing the company to include R&D expenses in its operating expenses. However, the staff's objections to the proposed level of the augmented R&D programs for test year 1974 are reasonable.

Based upon the discussion, supra, we adopt an amount of $58,029,000 for administrative and general expenses.

Table 2 contains SoCal's and the Commission staff's operating and maintenance expenses for test year 1974 together with a breakdown of their areas of differences and our adopted expenses of $526,820,000. The adopted expenses include additional sales tax expenses of $480,000 and additional postage expense of $749,000.

Taxes Other Than on Income

SoCal provided later information that current ad valorem tax costs would result in a $740,000 decrease below its estimate for the first installment of its 1973-1974 tax year and a like amount for the second installment. We are not persuaded by SoCal's arguments that no recognition should be given to this reduction because of potential offsetting increases of like magnitude in the second half of 1974 due to increased assessed valuations because of the possibility that there would be a reduction in federal revenue sharing funds available to reduce property tax rates, and because property tax rates may increase to the 1972-1973 fiscal year level. SoCal's estimates of average tax rates per $100 of assessed value are $11.855 for SoCal and $10.90 for PLS for 1972-1973, 1973-1974, and 1974-1975.

The adopted ad valorem tax of $18,459,000 reflects the full year effect of the reduction in rates and adoption of all of the staff's plant adjustments to rate base, with the exception of the capitalized wage adjustment proposed by the staff.

We are including an additional $86,000 for social security tax increases not contemplated in the original estimates, based upon the adopted operating expenses.

TABLE 2

SOUTHERN CALIFORNIA GAS COMPANY

Operation and Maintenance Expenses - Test Year 1974

Operating & Maintenance Expenses	SoCal	Commission Staff	Difference SoCal Exceeds Staff	Areas of Differences Between Southern California Gas Company and the Commission Staff									Adopted
				Use Per Firm Meter	Avg. No. of Firm Meters and Other Rev. Diffs.	PLS	Wage Adjustment	Basic Expense Estimates	Customer Installation Disallow.	Marketing	Public Relations Disallow.	Management Force Reduc.	
								(Dollars in Thousands)					
Production	$358,458	$358,812	$ (354)	$(10)	$	$(166)	$	$(178)	$	$	$	$	$356,554
Storage	5,890	5,683	207					207					5,631
Transmission	10,873	10,812	61					61					10,873
Distribution	55,812	54,189	1,623					501	1,122				54,932
Customer Accounts	30,906	30,854	52	(10)	(2)			64					31,515
Sales	12,000	8,430	3,570							3,570			8,746
A&G Inc. Fran. Reqs.	58,857	55,919	2,938	(38)	(10)			203			2,143	640	59,029
Subtotal O&M Expenses	532,796	524,699	8,097	(58)	(12)	(166)		858	1,122	3,570	2,143	640	526,340
Wage Increase Adjustment	-	(5,203)	5,203				5,203						
Sales Tax Increase	-	-	-										450
Adjusted Total O&M Exps.	532,796	519,496	13,300	(58)	(12)	(166)	5,203	858	1,122	3,570	2,143	640	526,820

The staff's estimate of payroll taxes reflects staff reductions inherent in its expense estimate and is $217,000 below SoCal's estimate. We will adopt payroll taxes of $5,948,000.

Income Taxes

Applicant and the Commission staff used the same tax rates and procedures to arrive at the income tax estimates for SoCal and PLS. Differences in operating revenues, operating expenses, payroll taxes, and of the plant base for the computation of ad valorem taxes all affect the estimates. Both the Commission staff and applicant used asset depreciation range and accelerated depreciation following the double declining balance method, where appropriate, in the calculation of tax depreciation. Both estimates reflected an annual amortization of ad valorem tax reserve based upon an accounting change authorized by this Commission, and an amortized amount of additional corporation franchise tax for SoCal, resulting from this Commission's permission in 1972 for SoCal to change its method of accounting for these purposes (SoCal's federal income tax calculation omitted the exclusion of this additional amount).

Applicant and the Commission staff used different approaches in the computation of interest deductions for income taxes. Applicant based its computations on actual or estimated interest rates applied separately to the monthly balances of long-term and short-term debt. The Commission staff states it derived interest by multiplying the estimated year-end 1974 weighted composite of long-term and short-term interest applied to the estimated weighted average debt for each utility in the year. However, the short-term rate used for tax purposes differed from that used for the rate of return determination.

The adopted results reflect further increases in the cost of short-term debt to 10 percent, and long-term debt to 9.5 percent, for the prospective long-term debt issues in 1974. These interest charges were utilized in our derivation of a year-end 1974 composite interest rate for tax purposes. We are adopting the same approach as we did in Decision No. 77975 dated November 24, 1970 in Application No. 51567. This decision states in part (mimeograph page 13):

> "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."

In our discussion of rate of return we recognize that SoCal and PLS would receive below the line benefits from the gains realized by reacquisition of their debt at a discount. The utilities did not pay any income tax on these gains as they have taken advantage of provisions of the Internal Revenue Code to offset the gain against depreciable property, which in turn reduces the depreciable property basis for computing income tax depreciation. We would be inconsistent if we authorized the gain to be transferred to surplus and also burden applicant's rate-payers with the additional expenses of paying higher taxes by reason of PLU taking advantage of these gains. We adopt the Commission staff approach (acceded to by SoCal) of not recognizing the IDI reductions in tax depreciation expenses for rate fixing purposes.

Rate Base

The Commission staff's estimate is based upon the updated plant estimate provided by applicant, less $812,000 because a portion of proposed transmission line will not be constructed, and an addition to plant based upon their higher estimate of customer growth. We adopt these adjustments. The Commission staff proposed a capitalized wage adjustment of $86,000. We reject this adjustment because we have annualized wages. The adopted working cash allowance of $11,406,000 at the last authorized 8.0 percent rate of return incorporates previously adopted revenues and expenses. The adopted working cash allowance at the 8.50 rate of return authorized herein is $9,301,000. The lead-lag data used in calculating the adopted working cash is based upon the 1971 lead-lag study with the staff modification using the 1972 state corporation franchise tax lags, based upon the actual practices of the company, and includes the Commission staff's adjustments for non-interest bearing customers' deposits and for unamortized state corporation franchise taxes. The 1972 lead-lag study furnished to the staff by the company is not appropriate because estimated 1974 revenues rather than recorded 1972 revenues were used for the revenue lag determination.

In 1967 SoCal sold certain properties to an affiliate, Pacific Lighting Properties Company (PLPC) at a loss. PLPC made $1,400,000 of improvements to this property and in 1972 sold a portion of the property to a non-affiliated third party for a $421,000 pre-income tax gain. The Commission staff recommends that on final sale of the property to an outside party a portion of the gain should be returned to SoCal to reduce the original loss and that $411,000 of the original loss presently remaining in SoCal's depreciation reserve account be disallowed for ratemaking purposes. The accumulated depreciation reserve of Southern Counties Gas Co. (Counties), now merged with SoCal, was reduced by approximately $488,000 in 1967 which represented the loss incurred by the utility on the sale of land and buildings. The Commission staff witness did not dispute the allocation between depreciable property and land made at that time. Counties made vigorous efforts to sell the property from July 1961 until it was sold to PLPC in 1967. We concur with SoCal that no adjustment is appropriate under these circumstances.

There are several instances where the Commission staff requested greater control over applicant's reclassification of properties from operative to non-operative properties. The Commission staff's recommendation was that SoCal and/or PLS should notify the Commission by letter of intent of planned reclassification of properties with book values for land in excess of $100,000 in time for the Commission to determine if it has any objections to the reclassification. The staff indicated that this approach would be followed in other utility rate proceedings. There is nothing on this record indicating any improper action on SoCal's or PLS' part in the disposition of non-operative properties. SoCal objects to the adoption of this recommendation because it would represent a fundamental change in the uniform classification of accounts. However, in the interest of our continuing overview of the operations of these utilities we will adopt the staff recommendation.

The record supports GSA's recommendation that utility plant in the amount of $5,000 be transferred from an operative to a non-operative status.

Authorized Revenue Increases

In order to achieve the authorized rate of return of 8.5 percent on rate base SoCal is in need of additional net revenues of $14,799,000 and gross revenues of $33,693,000. The additional revenue requirement gives consideration to increased uncollectible expense and franchise taxes and the decrease in the working cash requirement at authorized rates. Revenues derived from SoCal's requested rates, modified for the 0.023 GEDA adjustment, would total $702,275,000. This increase is excessive. The authorized rates and charges contained in Appendix B, attached to this order, designed to yield $682,750,000, are just and reasonable and present rates and charges, insofar as they differ therefrom, are for the future unjust and unreasonable.

Pacific Lighting Service Company

As pointed out earlier herein, a determination of PLS' costs of operation must be made to determine in turn a substantial portion of applicant's production expenses. PLS' 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 equal the product of its weighted average rate base and a fixed rate of return, presently 8.0 percent as fixed by Decision No. 80430.

Table 3 contains the PLS 1974 results of operations estimates of SoCal and the Commission staff, and the amounts adopted, all at an 8.0 percent rate of return, and the amounts adopted at the 8.50 percent rate of return authorized herein. The following discussion explains the basis used in arriving at the adopted amounts.

TABLE 3

PACIFIC LIGHTING SERVICE COMPANY

RESULTS OF OPERATION - TEST YEAR 1974

Item	At 8.00% Rate of Return				At 8.50% Rate of Return Authorized Herein
	So Cal	Commission Staff	Utility Exceeds Staff	Adopted	
	(Dollars in Thousands)				
Total Oper. Revenues	$144,548	$144,714	($166)	$142,492	$144,377
Operating Expenses					
Production	117,599	117,829	(230)	117,721	117,721
A & G Franchise Reqs.	130	115	15	114	116
Total Oper. Expenses	117,729	117,944	(215)	117,835	117,837
Taxes					
Taxes Other Than Income	4,328	4,295	33	4,108	4,108
Federal Income	(135)	209	(344)	(656)	71
State Corp. Franchise	218	290	(72)	(55)	115
Total Taxes	4,411	4,794	(383)	3,397	4,294
Depreciation	5,638	5,638	0	5,422	5,422
Return	16,770	16,338	432	15,838	16,824
Rate Base					
Gas Plant in Service	234,874	233,393	1,481	226,750	226,750
Const. Work in Prog. (N.I.B.)	475	475	0	475	475
Gas Stored Underground-Current	16,843	16,843	0	16,843	16,843
Prepaid Gas Purchases	31	31	0	31	31
Materials and Supplies	54	54	0	54	54
Working Cash	1,260	792	468	919	878
Unamort. Gas Dev. Costs	3,421	-	3,421	0	0
Subtotal	256,958	251,588	5,370	245,072	245,031
Depr. Reserve of Gas Plant	(47,328)	(47,238)	0	(47,112)	(47,112)
Total	$209,630	$204,260	$5,370	$197,960	$197,919
Rate of Return	8.00%	8.00%	-	8.00%	8.50%

Operating and Maintenance Expenses

The $230,000 difference in production expenses between SoCal and the Commission staff is related to the gas volumes purchased, which in turn are related to the interruptible exchange curtailments. Based upon the sales estimates to SoCal's customers PLS' production expenses total $117,721,000. This production expense is solely for gas costs. All labor and material costs associated with the operating and maintenance of the PLS system are reflected on SoCal's operating results. The only other operating and maintenance expense incurred by PLS is the payment of franchise fees. The adopted amount of franchise fees of $114,000 is based upon the staff's more up-to-date ratio of 0.08 percent of revenues.

Interest Deductions for Income Taxes

The interest deduction for income taxes is based upon the same considerations which were utilized for the SoCal deductions.

Rate Base

The Commission staff excluded 1,320 acres of buffer zone around the Aliso Canyon storage field which reduced rate base by $1,233,000 and reduced the Commission staff's ad valorem taxes by $33,000. SoCal demonstrated that this buffer is necessary for security of the injection and withdrawal facilities used in the operation of the gas field and to prevent undesirable interference with nearby residential developments. SoCal points out that if the buffer were not a part of the Aliso field, and if trees, which would be costly to plant and to maintain, were planted close to the critical facilities used in operating the field to provide a visual barrier and a sound barrier, that these trees could become a serious fire hazard.

The record shows that there were over 2,000 trespassing incidents on the Aliso project in approximately 15 months and that there is a substantial brush fire hazard in the area. SoCal should investigate the possibility of cultivating, or leasing for cultivation, of some of the fringe areas most frequently trespassed upon and of providing more substantial fencing in these areas. Possible benefits could be the generation of revenues from such cultivation, increased protection against fire hazards, improved appearance, and greater security for the facility. The staff's adjustment is rejected.

The acquired Aliso field oil operations were assigned to a non-utility affiliate. In apportioning costs the present worth of oil rights was calculated at a 13 percent rate and the present worth of gas rights was calculated at a 10 percent rate. The 13 percent rate was designed to meet the earnings objective of the affiliate. We do not quarrel with the transfer of the oil operations from applicant's operations so long as the objectives of the utility gas field operations continue to be paramount. We concur with the Commission staff's $210,000 PLS rate base adjustment which assigned costs based upon using a 10 percent interest rate in computing the present worth for both gas and oil rights and an associated ad valorem tax adjustment of $4,000.

GSA proposes to eliminate the Aliso field from rate base because net gas volumes injected are not available for sale in the test year. No withdrawals from Aliso are projected for the test year. We cannot expect PLS to develop this facility during a cold year when withdrawals from storage are necessary.

The rate base adjustment based upon as-expected construction of various portions of the Aliso project and capitalized interest during construction totals $7,914,000.

The related ad valorem tax and depreciation expense adjustments are each $216,000.

PLS has included $3,421,000 in rate base for R&D costs of non-GEDA type projects, i.e., coal gasification, SNG and various LNG projects such as contemplated projects in Alaska, Indonesia, and Australia. The staff did not include these amounts in the PLS rate base.

The expenditures are basically for preliminary engineering, engineering studies, environmental studies, and feasibility studies which are undertaken prior to making a final decision on the undertaking of a project. If the projects are undertaken, they will be carried out by affiliates of SoCal or PLS, or SoCal for the SNG project.

The preliminary funds related to a particular project would be assigned to that project at such time as the development was to be initiated. Since we have not authorized these projects and since the authorization for these projects, except for SNG project, would have to come from the FPC the appropriate vehicle would be for the affiliate requesting authorization of the project to include these costs in making its proposal for a cost of service filing to the FPC or for applicant to include the appropriate costs in an SNG certificate filing with this Commission. The justification for such expenditures could be tested upon that record. Consequently, we adopt the Commission staff's recommendation and delete these expenditures from the PLS rate base. Our action will not preclude applicant from requesting authorization to amortize unsuccessful project expenditures.

SoCal used the same allowance for PLS' working cash as authorized in Decision No. 80430. The Commission staff's estimate properly reflects the transfer of PLS' employees to SoCal as of January 1, 1972. Our determination of working cash in the amount of $919,000 is consistent with our determination of the adopted working cash for SoCal.

The adopted gross opening revenues for PLS which are incorporated in SoCal's production expenses are $142,492,000 at the 8.0 percent last authorized rate of return, and $144,377,000 at the 8.50 percent rate of return authorized herein.

B. RATE OF RETURN

In determining the appropriate rate of return in this proceeding, the Commission must balance the interests of SoCal's customers and those of the investors furnishing the funds necessary to meet the public utility service needs of PLU. We strive to give the customers the lowest rate practicable and at the same time to provide applicant with the funds necessary to construct the PLU systems and to provide SoCal's customers with reasonable service.

All of the common stock of SoCal and PLS is owned by their parent, Pacific Lighting Corporation (PLC). SoCal, the Commission staff, and Los Angeles ascribed PLC's preferred stock to the PLU capital structure. The funds derived from the preferred issues have been utilized for the same utility purposes SoCal or PLS could have utilized had they issued preferred stock in their own names. In arriving at our rate of return determination the financial requirements for the integrated operations of SoCal and PLS, designed to meet the needs of SoCal's customers, are appropriately treated as a single entity, PLU.

SoCal and PLS are constitutionally entitled to an opportunity to recover their operating costs and to earn a reasonable return on that portion of the PLU system which is lawfully devoted to public use. The rate of return on rate base provides for the payment of interest on debt, dividends on preferred stock, and earnings on common equity. A company's earnings level should be sufficient to permit it to attract capital on reasonable terms and to adequately compensate its investors. After considering all of the evidence, the Commission concluded that a rate of return of 8.50 percent is fair and reasonable for SoCal and PLS. We will now proceed to consider 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 the PLU system were presented by witness Jensen, for applicant, who initially recommended an 8.5 percent rate of return, but subsequently suggested that rates of return of 8.75 to 9.0 percent be considered if the then existing high rates on debt continued in effect;5/ by Commission staff witness, Scheibe, who recommended a rate of return of 8.15 percent; and by witness Kroman for the city of Los Angeles who recommended a rate of return of 8.2 percent.

SoCal contends that the rates of return for itself and for PLS must be at a level which will enable them to maintain their credit ratings, to attract capital on favorable terms so that the PLU systems can be expanded to meet the energy needs of SoCal's customers, and to provide investors with an adequate return.

SoCal points out that there is no significant difference between the PLU's capital structure as developed by the company and the Commission staff and that only minor differences exist between the imbedded costs of debt used by each of them (Exhibits 31 and 37) and that the difference of $7.8 million in gross revenue requirement stems almost entirely from the rate of earnings allowed on the 35 percent common stock equity ratio, namely, the 11,83 percent recommended by the Commission staff as compared to the 12.96 percent requested by SoCal.

5/ He suggested that the Commission could consider this rate of return request in relation to the overall increase requested.

In Decision No. 80430 dated August 29, 1972, rates were set for SoCal with a rate of return on rate base of 8.0 percent to produce an 11.65 percent earnings rate on common equity capital which represented 39.3 percent of the capitalization of PLU.

SoCal contends that its rate of return showing considers the economic environment and comparative data of companies with similar operations, size, and risk, which must be accorded great weight. Witness Jensen selected comparison companies on the basis of their natural gas distribution activities and relative revenue and plant sizes. His conclusions were that the five largest gas distribution systems were the most appropriate to compare with PLU; that electric companies may be compared to PLU; but that integrated gas companies are of a different character than gas distribution companies and they are more debt oriented than gas or electric distributors. PLU consists of an integrated transmission company and a distribution company.

Applicant's comparison of PLU with the five largest gas companies is summarized below:

Item	5 Largest Gas Distribution Companies		Pacific Lighting Utility System	
	1967-71	1972	1967-71	1972
Capital Ratios				
Debt	53.4%	54.7%	46.5%	51.8%
Preferred Stock	1.6	2.3	12.5	12.8
Common Equity	45.0	43.0	41.0	35.4
Earnings Rates				
Common Equity	14.25	14.56	9.94	11.01
Total Capital	9.05	9.32	7.00	7.57
Times Interest Earned	3.48	3.16	3.06	2.53

Witness Jensen testified that the low percentage holdings of institutional investors in PLC common stock compared to California electric and gas and electric utilities, to the five largest gas distributors, and to 10 electric companies (which in 1970 were close to the same size as PLU) justify higher earnings in order to increase PLC's relative market price to book ratio and to attract investor interest. Mr. Jensen also prepared comparative data for the four largest integrated natural gas holding companies, which are larger than PLU. He testified that the large gas and electric distribution operating utilities have greater earnings stability than PLU and that gas utilities are less capital intensive than electric or telephone utilities.

In our opinion, the possibility of divestiture of PLC's non-utility operations being ordered by the Securities and Exchange Commission could influence the choice of institutional investors. The market price of PLC would be affected by the earnings of its non-utility subsidiaries. These earnings were not explored on this record. SoCal's earnings stability should be improved by the rate spread and PGA adopted in this decision. The adopted rate spread, the PGA, and the previously authorized GEDA should serve to lessen the risk assumed by investors in PLU securities.

Since 1970, the PLU financing mix has shifted from predominantly internal financing to predominantly external financing. The estimated proportion of debt increased to a 55.2 percent peak (with PLC preferred stock allocated to PLU) in 1973. In this time span increases in the weighted average cost of debt and the amount of debt have exerted upward pressures on PLU's revenue requirements and have decreased the times interest coverage on its debt. These trends have been accentuated by increases in PLU's debt ratio. PLU's earned times interest coverage is higher than the averages of the largest 10 gas and 10 combination gas and electric company groups used in a Commission staff comparison for 1968 to 1972, inclusive.

In 1974 PLU proposes to reduce its short-term debt by approximately $59,000,000, to increase its long-term debt by $52,000,000, and to increase its common equity by $55,000,000, which would reduce debt to 52.5 percent of total capital. The decrease in short-term debt and contemplated new debt and equity financing in 1974 will tend to arrest both the growth in interest charges and the decline in times interest coverage.

Table 4 contains the capital ratios, cost rates, and weighted cost used in the rate of return determinations for PLU adopted in Decision No. 77975 for 1970 in Decision No. 80430 for 1972 and SoCal's original estimates for test year 1974. The table also includes times interest earned data.

TABLE 4

PACIFIC LIGHTING UTILITY SYSTEM

Rate of Earnings on Capital

Item	Capital Ratios	Cost Rates	Return Component
ORIGINAL - Test Year 1974			
Debt: Long Term	50.0%	6.24%	3.12%
Short Term	2.5	6.00	.15
Total Debt	52.5	6.23	3.27
Preferred Stock	12.4	5.47	.68
Common Equity	35.1	12.96	4.55
Total	100.0%		8.50%
Times Interest Earned			2.60
DECISION NO. 80430 - Test Year 1972			
Debt: Long Term	46.2%	5.82%	2.69%
Short Term	3.8	5.50	.21
Total Debt	50.0	5.80	2.90
Preferred Stock	10.7	4.83	.52
Common Equity	39.3	11.65	4.58
Total	100.0%		8.00%
Times Interest			2.76
DECISION NO. 77975 - Test Year 1970			
Debt	50.0%	4.56%	2.73%
Preferred Stock	12.0	4.83	.58
Common Equity	38.0	11.68	4.44
Total	100.0%		7.75%
Times Interest Earned			2.84

SoCal's revised rate of return computation assuming a continuation of increased capital costs is tabulated below:

Item	Capital Ratios	Cost Rates	Return Component With Common Stock at 13%	14%
Debt: Long Term	50.0%	6.42%(a)	3.210%	3.210%
Short Term	2.5	9.25(b)	.231	.231
Total Debt	52.5		3.441	3.441
Preferred Stock	12.4	5.47	.678	.678
Common Stock	35.1		4.563	4.914
Total	100.0%		8.682%	9.033%
TIMES INTEREST EARNED			2.52	2.63
FAIR RATE OF RETURN			8.75	9.00
Earnings on Common @ Fair Rate of Return			13.21%	13.92%
Times Interest Earned @ Fair Rate of Return			2.54	2.62

(a) New debt at 8-1/2% for SoCal and 8-5/8% for PLS.

(b) Prime rate in mid-August 1973.

Witness Scheibe's study of the cost of capital and rate of return showed changes in interest rates and debt issues; changes in PLU's capital structure and financing; earning rates on average total capital and on average net plant investment; revenues, expenses, and net income; average customers and per customer net investment, revenues, expenses, and net operating income; and nominal interest paid by major California utilities. PLU was compared to 10 electrics, 10 combination gas and electric companies, and Pacific Gas and Electric Company.

He testified that in making his analysis he did not rely on comparable earnings of other utilities, but considered such earnings as simply one of the many guideposts in arriving at a fair rate of return; that comparisons with industrials using unadjusted raw earnings data are bound to be misleading; that utility comparisons should be with investments in other enterprises having corresponding risks; that avoidance of circularity is achieved through use of judgment and consideration of factors other than statistical ones; that attrition in equity earnings caused by addition of plant at higher costs per unit of additional revenues, by the increase of expenses at a faster rate than corresponding revenues, and by increases in fixed charges constitute the basis for a rate application; that rate of return is the allowance for the capital needs of a company-debt, preferred, and common equity, and not a catch-all for every possible adjustment; and that a rate of return allowance should hopefully be suitable for a lengthy period of time but there is no justification for excessive allowances to avoid near future rate cases.

His recommended rate of return is 8.15 percent on rate base, including a judgment figure of 11.83 percent as the common equity allowance, which included consideration of 28 enumerated factors (Exhibit 37, pages 13-15). Two of these factors were consideration of other income, e.g., the gain on reacquired debt by the utility, and the Phase IV federal price control criteria that the increase will achieve the minimum rate of return needed to attract capital at reasonable costs and not impair the utility's credit. SoCal witness Jensen did not consider the below the line gain on reacquired debt, which will improve PLU earnings and which is included in the indenture determination of times interest coverage in arriving at his recommended rate of return.

The following tabulation contains the breakdown of witness Scheibe's recommended rate of return based upon estimated capital ratios as of December 31, 1974:

Item	Capital Ratios	Cost Rates	Return Component
Long-term Debt	50.0%	6.27%	3.14%
Short-term Debt	2.5	7.50	.19
Preferred Stock	12.5	5.47	.68
Common Equity	35.0	11.83	4.14
Total			8.15%

The Commission staff objected to SoCal's reliance on Decision No. 81919 dated September 25, 1973 in Edison's Application No. 53488 as support for its requested rate of return of 8.5 percent because Edison's authorized 8.2 percent rate of return on rate base, which was designed to yield 12.25 percent common equity return, gave heavy consideration to Edison's capital requirements, environmental, and regulatory problems.

Witness Kroman for the city of Los Angeles (Los Angeles) testified that:

(a) A reduction of applicant's debt expense by $2,560,000 to reflect 1974 estimated gains made by purchasing its debt on the open market at substantial discounts and disposing of them at par for sinking fund purposes would reduce the embedded cost of debt rate from 6.24 percent to 5.76 percent;

(b) The issue of treatment for reacquired debt was considered by the FPC and the New York Public Service Commission. Evidence was taken on whether to reduce debt requirements by the full debt discount in the year incurred or reduce debt requirements by spreading the aggregate accumulated debt discounts realized over the average life of new debt issued to finance such sinking fund transactions. The adopted treatment was to take an annual amortization of discounts and premiums over the remaining life of the debt being retired; and

(c) He did not have the data to make a calculation on the remaining life of debt basis and therefore recommended averaging the results of his full test year debt discount and average life of new sinking fund debt financing methods, which reduces debt expense by $1,672,000 to an adjusted debt cost of 6.00 percent (GSA concurred in this treatment).

Witness Kroman stated that witness Jensen began with an 8.5 percent rate of return and derived the allowance for common equity of 12.96 percent and 12.50 percent related to equity ratios of 35.1 percent and 37.6 percent in Applications Nos. 53797 and 52696. He criticized witness Jensen's heavy reliance on a five-company gas distribution group because there was no showing that the earnings of these companies were reasonable, and in fact, the earnings could be used to support a 16.8 percent return on common equity; that the selection of comparable companies used, changes in equity ratio of these companies, and the type of regulation all affect earnings. He points out that equity earnings on industrial groups, including financial, have declined since SoCal's last general rate proceeding; that the rate of growth of PLU's capitalization was diminishing rather than increasing; that there has been a general decline in times interest coverage for gas, electric, and combination gas and electric companies; that reliance on earlier levels of interest coverage without considering the declines in Aaa coverage would result in an unrealistically high rate of return requirement; that the projection of Aaa coverage to the year 1974 would fall below Mr. Jensen's times interest coverage for PLU which includes the Aa rated SoCal and the A rated PLS; and that the times interest coverage proposed by witness Jensen was considerably higher than indicated by extrapolation of trends of interest coverage of the 10 largest natural gas companies or of 10 selected electric utilities. Witness Kroman recommended an 8.2 percent rate of return by updating Decision No. 80430 by giving consideration to changes in the cost of long- and short-term debt, adjusting debt charges for gains on reacquired bonds, increased cost of preferred stock, changes in earnings of other utilities, changes in common equity, rates of return recently authorized by this Commission for other major utilities, relative growth in plant and capitalization, comparable risks, and comparable earnings. His update of cost components of the allowances authorized in Decision No. 80430 is tabulated below:

Item	Capital Ratios	Cost Rates	Return Component
Long-term Debt	46.2%	6.00%	2.77%
Short-term Debt	3.8	8.75	.33
Total Debt	50.0		3.10
Preferred Stock	10.7	5.47[a]	.59
Common Stock	39.3	11.41	4.48
Total	100.0%		8.17%
Times Interest Earned			2.64

(a) 11.65% x 1.031 x .95 = 11.41%

1.031 is a factor equal to the percentage increase in embedded debt incorporating an adjustment for reacquired debt. The .95 is an adjustment to reflect recent declines in earnings on equity of electric, gas, and telephone utilities.

His application of cost components to 1974 capitalization ratios, retaining the 50 percent debt ratio of Decision No. 80430, increasing the preferred ratio, and decreasing common equity following an alternate treatment suggested by Mr. Jensen, is tabulated below:

Item	Capital Ratios	Cost Rates	Return Component
Long-term Debt	50.0%	6.00%	3.00%
Preferred Stock	12.4	5.47	.68
Common Stock Equity	37.6	11.67[a]-11.83[b]	4.39-4.45
Total	100.0%		8.07-8.13%
Times Interest Earned			2.69-2.71

(a) A judgment amount utilizing comparisons with other utility groups' earnings after adjustments to reflect PLU's capitalization.

(b) A modification similar to that described in Footnote (a) to the prior tabulation with an additional upward adjustment to reflect the decline in the common stock capital ratio from that set forth in Decision No. 80430.

SoCal contends that the Commission has never adopted an adjustment to reflect profits on debt purchased at a discount, that witness Scheibe rejected this approach; that the full amount of interest payments would not be allowed in future years if witness Kroman's recommendation was adopted; and that with modifications to eliminate inconsistencies Mr. Kroman's computations would result in rates of return equal to or above that requested by SoCal.

SoCal and PLS credit these debt purchase gains to Account 421, Miscellaneous Non-operating Income. Earlier issues of PLU securities can be purchased at a discount on the open market but SoCal and PLS are the only entities which can realize the gain prior to maturity. These gains and capitalized interest act to provide a cushion on times interest coverage. Other entities could realize a gain or a loss by selling their SoCal or PLS bonds.

These debt issues were authorized by the Commission and the interest payments on that debt are lawful obligations of PLS and SoCal. We will not adjust the debt expense of PLU in this decision because of the gains realized on the reacquired debt.

GSA recommends that the Commission adopt an average year capital structure rather than end-of-year structure used in the evidentiary showings, an 11.4 percent return on common equity, and a rate of return on rate base of no more than 8.2 percent.

The city of San Diego recommends that the PLC preferred stock should not be ascribed to the PLU capitalization but that those dollars should be reflected as common equity. San Diego contends that the Commission has not included the preferred of AT&T in Pacific Telephone and Telegraph Company's (Pacific) capitalization ratio and it has awarded lower returns on Pacific's common equity than to utilities with 10 percent less common equity. Therefore San Diego contends that a rate of return of no more than 8.0 percent is adequate for PLU. San Diego's suggested capitalization ratios are as follows:

Item	Capital Ratios	Cost Rates	Return Component
Long-term Debt	50.0%	6.31%	3.155%
Preferred Stock	2.0	5.47	1.09
Common Stock	48.0	9.71[6/]	4.661
Total	100.0%		7.925%

San Diego's argument is not persuasive.

Based upon all relevant considerations, we find the following cost rates to be reasonable for the components of the PLU capital structure as of December 31, 1974:

(a) 12.35% on common equity;

(b) 5.47% on preferred stock, including the imputation of all of the PLC preferred stock to PLU;

(c) 10.00% on short-term debt; and

(d) 6.50 % on long-term debt.

PLS's 1973 debentures were issued at an effective rate of 8.38 percent. SoCal proposes to issue $35 million of its Aa rated bonds in October of 1974 and PLS proposes to issue $30 million of its A rated bonds in December of 1974. The determination of the cost rate for long-term debt is based upon Table No. 5 of Exhibit 37, (the Commission staff basis) adjusted to reflect the issuance of the 1973 PLS issue at 8.38 percent and the issuance of long-term debt at an average rate of 9.5 percent for the SoCal and PLS issues in 1974.

6/ Derived by weighing cost of PLC's preferred stock at 5.37 percent and its common stock at 11.0 percent (which is 1 percent over the weekly average earnings price ratio of PLC from January 5, 1973 to November 16, 1973).

We are adopting the Commission staff capital ratios. Application of the above-mentioned cost rates to the capital ratio results in an overall rate of return of 8.50 percent. The application of an 8.50 percent rate of return on the PLU rate base would provide an approximate times interest coverage before taxes on income of 2.56 and 1.89 after taxes. Giving consideration to the estimated $2,560,000 gain for 1974 related to the reacquisition of the PLU debt would increase the times interest coverage by approximately 0.08 both before and after taxes. The following tabulation contains the adopted rate of return computation:

PACIFIC LIGHTING UTILITY

Adopted Rate of Return

Item	Capital Ratios	Cost Rates	Return Component
Debt: Long Term	50.0%	6.50%[(a)]	3.25%
Short Term	2.5	10.00	.25
Total Debt	52.5	6.48	3.50
Preferred Stock	12.5	5.47	.68
Common Equity	35.0	12.35	4.32
Total	100.0%		8.50%

(a) Includes proposed 1974 PLU debt issues at average rate of 9.5 percent.

C. RATE SPREAD

SoCal's witness testified that his rate design reflects the rate relationships established in Decision No. 80430; the comments of the Commission in that decision as to future rate considerations; the rate design approach indicated by the Commission to be appropriate in meeting the problem of temperature sensitive earnings; that in addition he gave consideration to historical factors, allocated costs, value of service, socio-political factors, customer usage patterns, and levels of service to interruptible customers; that the additional costs to be reflected in rates are general in nature, as contrasted to an increase in the cost of gas, lending support to his use of a percentage increase as an overall approach in spreading the revenue increase. His consideration of these factors resulted in a non-uniform percentage increase both to classes of service and to individual rate schedules and rate blocks.

SoCal's proposed rates would result in the following percentage increases by class of service: firm general service, excluding gas engine, 7.6 percent; gas engine, 8.2 percent; regular interruptible, 11.4 percent; utility electric generation, 8.2 percent; and wholesale, 8.2 percent. The overall increase was designed to yield 8.2 percent.

SoCal has proposed a reduction in a number of rate blocks in the firm general natural gas schedules (G-1 - G-5).

For Schedule G-61, service to San Diego Gas & Electric Company, SoCal proposes to set the commodity charge equal to the proposed Schedule G-58 rate consistent with the rate treatment in Decision No. 80430; to increase the peaking demand by the system average percentage increase; to combine the additional peaking demand commodity rates and derive at a single rate established at an historical level of 1.5 times the average cost of out-of-state gas; to leave the monthly facility charge at its present level; and to arrive at the balance of the G-61 revenue requirement in the monthly demand charge.

SoCal's proposal for Schedule G-60, service to the city of Long Beach gas department, is to apply the system average percentage increase to the monthly demand charge, the various commodity rates, and the annual charge for additional peaking demand.

For Schedule G-58 SoCal proposes the system average increase of 8.2 percent.

In its design of regular interruptible rates SoCal gave recognition to the widening differential in levels of service between utility electric generation customers and regular interruptible industrial customers; and between the various priorities within the regular interruptible class. It proposes increases ranging from 9 - 14 percent for regular interruptible rates and to narrow the rate differential between closed Schedule G-50-T and Schedule G-50. The G-53-T rate for supplemental service to Monolith Portland Cement Company proposed by SoCal reflects the agreement between it and PG&E regarding exchange deliveries.

A system average increase is proposed by applicant for street and outdoor lighting, Schedule G-30, and gas engine, Schedule G-45.

SoCal proposes that the remainder of the revenue requirement increase for the test year be assigned to the firm general service class which would result in a 7.6 percent increase. For Schedule G-1 - G-5 the proposed rate design provides for an increase of 75 cents per month in the initial block charge, increases of 7.6 percent in the next twenty-eight-thermal unit block, and for all usage over the 1,000 thermal units per month tail block rate (except Schedule G-20 where the blocking would remain unchanged but the rate for the tail block, for usage in excess of 20,000 thermal units per month, would be identical to the tail block rate proposed for Schedules G-1 to G-5 and G-40). This proposal envisions a decrease in the third block, the 970 block, where the bulk of the consumption exists within the G-1 to G-5 Schedules. SoCal seeks to utilize the lowest practicable rate possible for the 970 thermal unit block to minimize the effect of temperature sensitivity on its earnings. The Commission staff brief points out that that type of rate blocking would have a negative impact on SoCal's conservation efforts. The company's proposal for optional Schedule G-10 rates would continue the minimum charge at one dollar per month less than the initial block charge for the general service rate applicable in the same area with a break-even point with those local rates at 30 thermal units per month. SoCal contends that using the same tail block rates for Schedules G-20 and G-40 as it proposes for Schedules G-1 through G-5 would more nearly equate service under these schedules to G-1 to G-5. SoCal proposes to increase the initial block rates of Schedules G-20 and G-40 by a lesser amount than the average rate for comparable usage under Schedule G-1 and to reduce the number of rate blocks in Schedule G-40 to more nearly align it to the proposed rate blocking of Schedules G-1 to G-5.

SoCal's witness testified that he initially investigated the possibility of a rate design with a 50 cent increase in the minimum charge for Schedules G-1 through G-5 under hot year and cold year temperature assumptions of delivery and that the comparison indicated that the 50 cent increase reduced the revenue differential of about $46.4 million by only $1.1 million and that the 75 cent increase proposed for the initial block charge would permit a reduction of about $4 million in the revenue variation between hot and cold years. He felt that this increase was justified and was supported by the company-sponsored cost of service study which showed that firm's general service direct assigned costs are over $58 per customer per year or almost $5 per customer per month, excluding allocation of fixed costs relating to distribution mains, transmission mains, or storage used in common with other classes of customers, and which are incurred whether or not any gas is delivered. The minimum charge proposed for Schedule G-1 is $3.70446 for two thermal units or less, increasing to $4.81446 under Schedule G-5. He further stated that these costs would be applicable in the same order of magnitude to G-10 customers because the costs relating to meter services, billing, and general office operations are applicable at virtually the same level to small G-10 customers as to large residential customers, although there would be some reduction in appliance servicing costs of G-10 customers who may have fewer appliances. SoCal proposes a class average increase to be applied to the air-conditioning discounts, and a firm average percentage increase for Schedule G-30, street and outdoor lighting.

A Commission staff witness concurred with SoCal's proposal that the largest increase would be assigned to the regular interruptible classes of service, but his recommendation was based upon the basic concept that rates for gas service should not be lower than the average cost of gas expressed in cents per million Btu for G-58 customers and for the commodity rate of Schedule G-61. The G-58 rate was his starting point for a regular interruptible rate design which gives consideration to the level of service for the various interruptible schedules as a prime factor in the assignment of rate increases to these classes. His rate spread assigned a higher than system average increase to gas engine customers, air-conditioning service, and street and outdoor lighting service. He adopted SoCal's proposals that the average system increase be assigned to wholesale customers and that firm customers be assigned the remaining balance which was less than the system average increase; that there should be a reduction in the number of rate blocks in the firm schedules and in the G-50 Schedule; and that there should be a common tail block rate for all measured firm schedules except for gas engine service. He also testified that the effect of SoCal's proposed rate structure would mean increases on the order of 20 percent to its smallest customers and decreases to certain larger users; that weather sensitive earnings can be important, but that he did not concur with SoCal's rate design for firm customers as other factors such as the critical gas supply may be of greater importance at the present time. He proposed that the assignment of cost to the various rate blocks of the firm schedules be generally based upon equal percentage increases.

CMA contends that applicant's rate design is unfair and discriminatory to the regular interruptible class. CMA places principal reliance on applicant's base supply and load equation cost allocation study which yields the results contained in the following tabulation:

Class of Service	Deliveries	Cost of Service Revenues in ¢/Mcf: Excl. Franch.	Incl. Franch.	1/1/73 Rates(a)	Proposed Rates(a)
Firm General Gas Service	442,193	121.2	122.8	109.9	118.3
Gas Engine	5,699	67.7	68.6	60.2	65.1
Regular Interruptible Interruptible Schs. G-50, G-50-T & G-53-T	177,164	44.8	45.4	50.1	55.8
Util. Elec. Generation Sch. G-58	61,366	38.4	38.9	37.9	41.0
Wholesale - City of Long Beach Schs. G-69 & G-60	15,514	53.8	54.5	55.1	59.7
Wholesale - SDG&E Sch. G-61	80,665	52.2	52.8	48.1	52.0
Total	782,601	88.5	89.7	82.9	89.7

(a) Includes the GEDA charge of .023 cents per therm which has not been included in Table 1 of this decision nor in the adopted revenues at proposed rates. The present rates column includes the offset increase which became effective on February 15, 1974.

CMA contends that SoCal's regular interruptible customers would bear a burden which is $2,807,000 per year greater (and general service would bear a corresponding reduction) than would be the case if the additional revenue burden were distributed rateably, among all classes, based upon SoCal's cost of service study; that the gas available for interruptible gas customers will decline from about 43 percent in 1973 to 6 percent in 1977 and zero percent in 1982.

SoCal argues that it is striving to prevent a decline to a zero percent service level for interruptible customers by 1982 and rejects CMA's suggestion that a greater burden should now be assigned to firm customers in anticipation of such a decline in level of service.

CMA proposes an even greater increase in initial block charges than those proposed by SoCal and a lesser dependence on declining regular interruptible sales to compensate for alleged shortcomings in applicant's rate design. CMA contends that a large proportion of SoCal's general service customers do not pay enough to cover even the directly assigned fixed costs of serving them; that at SoCal's proposed rates the average firm general service revenue would be 4.5 cents per Mcf below applicant's allocated costs; that regular interruptible rates are now 5.7 (4.7 cents per Mcf based upon Table 1 of Exhibit 4) cents per Mcf above costs and that this would increase to 10.4 cents per Mcf under SoCal's proposed rates.

CMA contends that the relationships established in Decision No. 80430 have already been impaired by subsequent offset and tracking increases applied on a uniform cents per Mcf basis, the effect of which is to narrow the rate differentials between classes; that these differentials would be further narrowed under applicant's varying percentage increases proposed herein for those classes; that SoCal, in fact, did not build upon prior rate relationships except by applying differing percentage increases to present rates; that cost of alternate fuels was once a ceiling on interruptible gas but that this is no longer the case; that SoCal did not rely upon the cost of alternate fuels in its proposed rates for any class of service; that applicant's industrial customers are entitled to the Commission's protection against successive and unjustified increases in regular interruptible rates; that the interruptible class which is contra-weather sensitive is called upon to compensate SoCal, through higher rates, for the unstable use characteristics of the general service class; that applicant's proposal under a value of service concept does not include the cost of alternate fuels but considers relative levels of service, that the evidence shows that the level of satisfaction of regular interruptible requirements is declining from

90 percent in 1973 and 74 percent in 1974 while those of firm customers remain constant at 100 percent; and that consideration of this factor between firm and regular interruptible customers would justify greater increases for firm service and lesser increases for regular interruptible service than those proposed by applicant; that applicant's proposed 75 cent increase in the initial block charge is completely nullified by its failure to seek at least an average percentage increase in revenues from the general service class. CMA also contends that the application of a percentage increase to the whole of existing rates results in an improper distribution for the recovery of non-gas costs; that the interruptible customers are being required to pay approximately $2,000,000 annually for the costs of the Aliso gas storage facility which contributes to the reduction in the level of service which they would otherwise receive in 1974. CMA attacks the Commission staff's rate design as being more unsound and discriminatory than that of applicant for firm industrial, regular interruptible, and steam plant customers; CMA points out that the Commission staff witness gave no consideration to cost of service in arriving at his proposed rate; that the staff witness testified that pricing of gas to interruptible customers would be wholly ineffective for conservation purposes given the present gas supply situation; and that the staff's proposed rate design would do little to help out the stability of earnings problem.

CMA proposes an alternative rate based upon rolling out the average cost of gas from present rates and increasing each rate by a uniform percentage of 17.86 percent, attributable to non-gas costs, and then adding the gas costs plus an increment for increased charges from PLS to each rate. CMA argues that its proposal would produce a higher percentage increase for the general service class and a lower percentage increase for all other classes than under applicant's proposal, but such revenues from the general service class will still not cover the allocation of costs. CMA argues that its design would provide for greater security from erosion of earnings resulting from the rapid decline in gas supply available for interruptible sales.

SoCal argues that the maintenance of rate relationships in the manner suggested by CMA is unusual; that the cost of gas is not an identifiable portion of individual rates nor is the cost of the Aliso facility identifiable in any rate; and that cost allocation is only one factor to be considered in the design of fair and reasonable rates.

The Commission staff points out that testimony shows that the cost of gas used in the CMA study was not the same as that in the cost allocation study of SoCal and that following through on the CMA proposal would result in reductions for certain rates. The staff suggests that if the average cost of gas is as calculated in the CMA exhibit the Commission could consider that cost as the lowest rate level and set interruptible rates at levels that reflect levels of service and this average cost of gas.

Edison argues that present regulatory practices were designed to protect consumers of public utility services, to avoid exorbitant, what the traffic will bear, prices having no reasonable relationship to the cost of providing such service. Edison contends that the sale of gas to interruptible customers having no demand rights at any rate above the commodity cost to SoCal can do nothing but contribute to the overall economic operation of SoCal's system and be financially beneficial to it and to its other customers; that the alternate cost allocation studies (the extreme peak day method and the annual average day method) did not yield valid results; that the base supply and load equation method shows that at the proposed rates there would be an inappropriate margin of revenue over the allocated costs for interruptible customers, that if SoCal's proposal were followed, steam plants and regular interruptible customers would pay more than the system average increase and the firm general service class would receive the benefits of that differential, which would be contrary to the Commission's intent in Decision No. 80430; that in modifying the rate design established in Decision No. 80430 SoCal has failed to give appropriate consideration to the very significant deterioration in levels of gas service available to its steam electric customers since that time, resulting in substantial part from federal curtailment orders issued after that decision; that in 1971 the level of service for all retail and wholesale electric utility generation was 61.7 percent (for Edison 58 percent) and that SoCal anticipates that the 1974 level of service for retail and wholesale electric utility generation on its system would be about 1/5 as high, 12.7 percent, as compared to 1971, and that Edison would only have a 10.8 percent level of service in 1974; that the evidence in this proceeding shows that the rate relationships established in the prior proceedings are inappropriate and that the Commission staff recommendation of a rate floor equal to the average cost of gas includes both demand and commodity cost components and Edison has no demand rights, but steam electric customers (e.g., Edison) provide a valuable service to SoCal by enabling it to utilize this service as a means of seasonal load equation balancing; that in so doing the interruptible customers incur substantial costs required to provide storage and alternate fuel backup; and that the staff proposal would give no weight to these factors in their average cost of gas concept.

The city of San Diego questioned the assignment of storage costs to SDG&E because 90 percent of its service is taken directly from a main transmission line and also questions the assignment of a higher transmission cost than the overall average transmission cost because of SDG&E's load factor. San Diego also alleges that the facility charge to SDG&E is excessive and therefore recommends a reduction of 2.4 cents per Mcf in the assigned charges to SDG&E. The evidence shows that SoCal operates an integrated storage, transmission, and distribution system to meet the firm requirements of its retail and wholesale customers and to supply portions of the interruptible retail and wholesale requirements on its system pursuant to the orders of the Commission.

San Diego also contends that the coincidental extreme peak day method of cost allocation supports the logic of a reduction to SDG&E and that the annual average day method is inappropriate for consideration in this proceeding. San Diego requests the Commission to reject applicant's and the staff's proposed methods of spreading the increase by giving consideration to cost allocation methods along the lines developed in its brief and to the fact that any increase should be applied to customer and demand components of the rate because the commodity portion of their rates has been increased by tracking and offset increases since the last major rate case. With regard to Schedule G-61 San Diego recommends that the Commission delete the facility charge and make any adjustments necessary in the customer and demand portions of the rate.

A GSA witness recommends that there be a military rate schedule applicable systemwide to installations which own or operate their own distribution systems and take firm gas for the combined three uses of cooking, water heating, and space heating. GSA alleges chaos in present service to military facilities and contends that the paramount question is "Is it fair and equitable to force military installations to take service and pay rates under an all-purpose or general service rate schedule which is also available to a variety of customers displaying different load characteristics and cost responsibility?"

GSA also contends that the PGA and proposed rates authorized herein could, if determined incorrectly, aggravate seriously the energy crises. SoCal points out that the proportion of service under firm schedules provided under Schedule G-20 is minor. The so-called chaotic condition in military rate schedules may be caused in part by the attempt of the military to coerce SoCal into extending its service area under Schedule G-20 to new customers. The military withheld payment for service at Lemoore Naval Air Station. SoCal properly sought to serve the station under Schedules G-6[7] and G-4 for the period from April of 1972 to September of 1972. The then unpaid compensation due under Schedules G-4 and G-6 totaled $170,715. Had the G-20 rate been in effect the compensation would have been $169,948, a difference of $766 or .045 percent.

Exhibit 50, which contains the test year revenue derived from SoCal's G-20 and G-40 customers at present rates and proposed rates, indicates that revenues for G-20 customers are below the average increase proposed for firm service.

7/ A prior schedule which was applicable during the time the billing was being disputed.

A Commission staff witness recommended that a larger than average increase be assigned to G-20 and G-40 rates to make them more nearly equivalent to G-1 rates. This resulted in part from his recommendation of lower general service minimum charges than requested by applicant.

The Commission staff contends that GSA stressed the three-use requirement in the present G-20 Schedule as justification for extending that schedule to the entire service area of applicant; that SoCal's witness pointed out that the load factor for the G-20 customers was approximately the same as those of the general service group and that the three-use criteria do not make military housing unique because of applicant's saturation for these three uses. The staff suggests that perhaps the best solution to this problem is to relieve the military of the three-use criteria by eliminating this schedule entirely.

SoCal has customers on its general service schedules who, in common with G-20 customers, own their own distribution systems and have the responsibility of operating and maintaining their systems at their own expense. (One of SoCal's G-1 customers owns and operates its own system which supplies approximately twice the number of housing units as the largest G-20 customer.) There is a cost differential advantage to such customers and to G-20 customers because most of their consumption is purchased at the tail block rate. If SoCal were to own and operate a system which provides a meter for each separate housing unit, the average bill per housing unit would be higher. This differential in gas cost per housing unit would offset or exceed the cost of operating and maintaining a private distribution system.

In Decision No. 77975 the Commission reiterated the limitation of cost allocation data on the PLU system as follows:

> "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."

In prior years when there was an abundant supply of gas and fuel costs were competitive with those of gas and environmental constraints on the burning of fuel oil were not a factor in fuel choice, there was an argument for the division of the cost of out-of-state gas on a demand-commodity basis. Rates authorized permitted SoCal to sell gas at competitive rates to its interuptible customers.

In this time of gas shortage, SoCal has been unable to obtain deliveries of contracted for out-of-state demand quantities. SoCal is seeking new, expensive, and massive increments of gas supply to meet its system requirements. It would obviously welcome a massive additional supply of natural gas being made available from its out-of-state suppliers. Its interruptible customers would welcome such new increments of gas at prices based on an average cost of gas. The costs of alternate industrial fuels, principally low sulfur fuel oil, are several times as expensive as the costs of natural gas, for the purposes required by SoCal's interruptible customers.

At this time the demand component in SoCal's purchases of natural gas, which benefits its suppliers, is not based upon any meaningful demand-commodity relationship. FPC authorized rate designs appear to be trending toward commodity cost only rates for interstate transmission of gas.

In Decision No. 81050 dated February 14, 1973 we took official notice of FPC's letter order dated December 29, 1972 in RP 72-150 and RP 72-155, authorizing El Paso's rate proposal in RP 72-150, which reduced demand charges and increased commodity charges. In Decision No. 82042 dated October 24, 1973 we noted the demand charge adjustment which would reduce demand charge payments when El Paso's deliveries are less than 100 percent of its contract demand.

On October 31, 1973 the FPC issued Opinion No. 671 in United Gas Pipeline Company's (United) Docket No. RP 72-75 (Phase II). The FPC revised the method of classifying costs so that more of the fixed costs are shifted from the demand to the commodity category. This increases costs to low priority direct customers and interruptible customers who are able to use competitive fuel. In that proceeding sales to United's customers were limited by supplies of gas available, not by pipeline capacity. The same situation prevails in the case of SoCal's out-of-state suppliers. The FPC indicated that it was not going to a complete volumetric method of pricing gas at this time because such a sudden change may be disruptive to United's system (which includes nonjurisdictional customers).

In Opinion No. 671-A in the same docket, in which the FPC denied rehearing, the opinion and order states:

> We also recognize, however, that the 25-75 classification of fixed costs between the demand and commodity components of the rates adopted therein may require further revision in future cases "to establish pipeline rates for industrial use more in line with the cost of competitive fuels available for such use (Page 16). Thus, we made it clear that the continuing natural gas shortage portends even higher commodity rate levels."

SoCal's rate allocation study contains demand allocations for its out-of-state gas supply. 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.

While there are undenied benefits to SoCal of having customers on its system whose usage can be curtailed to meet the needs of its firm customers, we are not convinced that a theoretical allocation apportioning such benefits to yield rates below the average cost of gas is reasonable. In arriving at our adopted rate spread we have considered the rate design criteria proposed by the parties and we take cognizance of the cost of alternate fuels. In apportioning the increased revenue requirements we are adopting the basic premise of the Commission staff that rates should not be below the average cost of gas.

The adopted rate for the G-58 customers and the G-61 commodity charge will lessen SoCal's revenue losses when below average firm consumption results in the release of additional gas volumes for interruptible uses. Regular interruptible rates authorized herein give consideration to levels of service anticipated under the various rate schedules.

In the interests of energy conservation we are narrowing the incentive inherent in the air-conditioning rate differential by reflecting the 100 percent rate recommended by the Commission staff and its 100 percent rate for Schedule G-30.

The city of Long Beach offered no evidence during the proceeding. However, at the close of hearings Long Beach filed a brief requesting a restructuring of rates similar to the G-61 rates, to facilitate gas sales to Edison. We concur with the Commission staff's objection to this procedure in that there should have been an evidentiary testing on this record of that change. Long Beach's proposal is a significant change in concept in the restructuring of the G-60 rate schedule.

We concur with SDG&E's request that its revised peaking demands incorporated in SoCal's Advice Letter No. 882, authorized by Resolution No. G-1602, should be incorporated in the San Diego rate design. We adopt the recommendation of SoCal and the Commission staff for a system average wholesale rate increase and the staff concept for the G-61 commodity rate.

The adopted rate blocking for Schedules G-1 through G-5 incorporates a higher than class average increase for the first two thermal units to lessen the impact of the temperature-sensitive revenue swing. The evidence supports the Commission staff proposal that approximately equal percentages of increase be adopted for the remaining G-1 to G-5 blocks. No adequate rationale for a billing decrease, which would occur under SoCal's proposal for certain consumption levels, was demonstrated on this record.

We adopt the Commission staff's recommendation that a higher than average increase should be charged to gas engine customers to maintain historical relationships with other rate schedules. Table 5 is the summary of authorized increases for test year 1974. We find that these increases, based upon the rates contained in Appendix B to this order, are just and reasonable.

TABLE 5

SOUTHERN CALIFORNIA GAS COMPANY

Summary of Authorized Increases

Test Year 1974

Class of Service	Adopted Sales MMcf	Rev. Adopted Sales 2/15/73 Rates[b]	Authorized Increase: Amount M$	Authorized Increase: Per-cent	Authorized Increase: Cents Per Mcf	Avg. Rev. After Inc. Cents Per Mcf	Avg. Rev. After Inc. Cents Per Therm
General Service	443,659	486,172[a]	17,615	3.62	3.97	113.55	10.870
Gas Engine	5,699	3,416	366	10.71	6.42	66.36	6.320
Regular Interr.	177,242	88,244	10,743	12.17	6.06	55.85	5.314
Steam Elec. Plnt.	60,077	22,640	2,539	11.21	4.23	41.91	3.984
Wholesale	96,173	47,120	2,430	5.16	2.53	51.52	4.902
Subtotal	782,850	647,592	33,693	5.20	4.30	87.03	8.308
Other Gas Rev.		1,465	-	-	-	-	-
Total Rev.		649,057					

a/ Includes an increase for the customers served under G-20 and G-40. Such customers transferred to General Service Schedules at proposed rates.

b/ Modified per Footnote 3 herein (p. 9).

D. PROPOSED PURCHASE GAS ADJUSTMENT CLAUSE

SoCal has requested a purchase gas adjustment clause (PGA) to replace the tracking authority in effect through the effective date of this order and to offset other changes in the cost of gas. SoCal states that if it is authorized to utilize the PGA that it would eliminate the necessity to file frequent applications to extend its tracking authorization, to update test years used in establishing appropriate tracking and/or offset charges; and to offset gas cost increases resulting from basic rate increases made effective by its suppliers; that elimination of such filings would result in considerable savings in time and manpower, both to the company and the Commission; and that at the same time, the Commission will retain full control over the company's rates through its continuing surveillance over the results of operations. The PGA procedure proposed by SoCal would provide among other things that:

(a) Commodity rates in all filed rate schedules except G-30 shall include the applicable PGA.

(b) Filings could be made to reflect changes equal or greater than 0.025 cents per Mcf in the weighted average unit cost of gas.

(c) Weighted average unit cost would be based on estimated annual volumes for the succeeding 12 months.

(d) Changes in the PGA would be spread on a uniform cents-per-therm or thermal unit basis, including the supplemental service special G-53-T rate for Monolith Portland Cement Company and the additional peaking commodity rate in Schedule G-61 for SDG&E.

(e) Filings would become effective on the effective date of the change in unit cost or 15 days after the date of filing.

The Commission staff supported the authorization of the PGA clause at this time for SoCal with the following modifications as to filings:

(a) Each PGA should be filed with the California Public Utilities Commission 30 days before the proposed effective date.

(b) The PGA should not be revised more often than six times each year.

The Commission staff also recommended that:

(a) Any refund from a supplier should be refunded with 7 percent interest to the utility customers. A refund plan should be filed with the Commission when such refunds have accumulated to a total of $1,000,000 or more.

(b) No change in the PGA should become effective without Commission approval.

(c) Results of operation reports should be filed by April 15 of each year providing estimated operations for the ensuing year and recorded and adjusted operations for the prior year. The adjustments would be for normalized temperatures, possibly reflecting Commission adopted or imputed trends in per customer firm usage, and adjustments made by the Commission in the preceding rate case (e.g., disallowance of a portion of sales expenses).

(d) A report on the reasonableness of the prices paid for gas should be filed by April 15 of each year.

SoCal agrees to the staff's revised limitation, based on the potential number of rate filings by its suppliers, that the number of PGA filings be restricted to no more than six per year, filed 30 days or more before the effective date of the filing, which would not go into effect before the issuance of a resolution of the Commission. SoCal supports the Commission staff proposals on refunds from suppliers, the filing of the results of operation report on a recorded and temperature adjusted basis. We conclude that these modifications are reasonable.

SoCal opposes adjusting the recorded or temperature adjusted results of operation to reflect disallowances or deductions made by the Commission in its prior rate decision. SoCal points out that relationships are not static in expense levels and that almost any adjustment made in a prior period may no longer be applicable to the period under consideration. SoCal contends that the prior year's result of operations adjusted for average weather conditions, as reflected in use per meter, would give the Commission adequate information to maintain its continuing surveillance on the company's operations. SoCal also opposes the filing of a prospective results of operation report because it feels that there will be no value in such a report in enabling the Commission to pass upon the propriety of a PGA filing and because of the ongoing purpose of PGA is to offset future gas cost increases. SoCal states that the PGA procedure is intended only to enable it to expeditiously adjust rates to recover increases in its average cost of gas and that since all rates would be adjusted uniformly, on a cents-per-therm or equivalent basis, the proper test is a comparison of SoCal's revenue increase after PGA adjustments with SoCal's gas cost increase caused by supplier rate increases for the prior year.

The following points in opposition to, or proposing modifications of, SoCal's proposals made by other parties are as follows:

(a) GSA concludes that existing procedures are satisfactory to enable SoCal to adequately recover increased purchased gas costs. GSA objects to the possibility of any type of gas being included in the PGA whether regulated or not and regardless of cost because these costs could be considerably in excess of gas costs from traditional sources, and the rolling in of new high priced gas with other gas pool supplies would result in the sale of new gas below the incremental cost of such gas. GSA states that under the GEDA procedure companies affiliated with SoCal, whose interests are those of suppliers, would be in opposition to SoCal's interest as a distributor to keep the cost of gas down and that the Commission must be sure that SoCal has an incentive to bargain for the lowest possible cost of gas.

As to the issue of inclusion of new supplies in the PGA a Commission staff witness stated that basic to his inclusion of new supplies, such as a LNG filing, in the PGA was the assumption that before any high price increment was included in SoCal's supply there would be a certificate proceeding which would state the rate design implications of bringing in this new source of supply.

(b) CMA opposed inclusion of peaking gas supplies in the PGA because a portion of such costs would be paid by interruptible customers who would not benefit from these supplies.

SoCal argues that peaking gas amounts to slightly more than one percent of its 1974 test year supply and that CMA's concern that interruptible customers would be required to participate in the cost of such high cost supplies is de minimus and that furthermore the Commission's policy as set forth in Decision No. 80430 is that the spread of this type of increase to customer classes should be on a uniform cents-per-therm basis. SDG&E's reasons for opposing the CMA proposal for exclusion of the cost of peaking gas from the PGA for use in determining changes in interruptible rates are:

"SoCal's utilization of the California source gas for peaking purposes is beneficial to both firm and interruptible customers and the cost should be included in the PGA formula. If California source gas were not obtained for peaking purposes, it would be necessary during the summer months for SoCal to curtail interruptible customers to an even greater extent to inject gas supplies into storage for the winter to replace the California source gas if it were not otherwise available to provide peaking deliveries. This would further erode service to the interruptible customers. Thus the interruptible customers receive a direct benefit from the California source gas used for peaking because they receive gas service which would not otherwise be available to meet their demands. For these reasons, it is appropriate for the interruptible customers to share in the cost of such gas. Otherwise, the interruptible customers would receive the cheaper gas in the summer which could have been injected into storage for the future use of the firm customers, and the firm customers in turn would receive the more expensive peaking gas as a replacement for which they would absorb the total cost."

CMA requested that the number of cost changes under PGA filings be limited to four per year because the intent was not to eliminate slippage resulting from increases in the cost of gas and that four annual adjustments should substantially reduce SoCal's risk, while providing it with an incentive to seek out the lowest possible gas cost.

Exhibit 26 contains a computation of the average cost of gas for SoCal's test year 1974 and it also shows the revision on a pro forma basis of an additional supply of 73,000 M^{2}cf of gas at $1.25 per Mcf along with a decrease in purchases of California interruptible exchange supplies brought about by a decline in curtailment. The $1.25 per Mcf is the hypothetical cost of obtaining a new increment of gas from Canadian sources in 1975. The effect of adding this new supply to SoCal's gas pool would be to increase the cost of gas from 41.86 cents per Mcf to 48.34 cents per Mcf, a 16 percent increase. This new rate would be equal to .664 cents-per-therm. The magnitude of this increase together with SoCal's testimony in Case No. 9642 that its first increment of LNG would cost $1.82 per Mcf justify our requiring SoCal to file an application for authority to include such large and costly new increments of gas to the gas pool used for determination of the PGA.

The future implications of our excluding peaking gas or new and higher cost additions from the PGA pool could result in establishment of an incremental pricing structure or special contract deliveries to interruptible customers similar to the special contract deliveries to SDG&E and the G-58 customers authorized in 1972. There could be administrative and/or financial problems associated with either of these approaches. We find it reasonable to include peaking gas in the PGA pool. The issue of how to deal with new costly gas increments can be considered on a case-by-case basis. Considerations of how to deal with the pricing of new gas supplies support our prior determination that rates for gas service should not be less than the average cost of gas.

We find it reasonable to authorize SoCal to file tariff sheets incorporating its PGA with the modifications contained in this opinion. SoCal will be authorized to make up to six PGA filings per year. The PGA authorized should be applied on a uniform cents-per-therm or thermal unit, or equivalent (on the basis determined in Exhibit 40 for Schedule G-30) basis.

The staff recommendation regarding the filing of a projected results of operation report is reasonable, except that the only modifications required will be for normalized temperature adjusted sales and customer growth.

As heretofore noted, past decisions authorizing tracking or offset increases have contained provisions that these increases would be subject to refund and reduction if lower rates were ordered by the FPC, and that the increase was also subject to refund if there was any excess of charges over increases in expenses, or if the end of year temperature adjusted rate of return exceeded the authorized rate(s) of return up to the amount of the authorized increase. In authorizing the PGA we will retain all of these provisions. The PGA is intended to expeditiously allow SoCal to pass through supplier increases without hearing. The average price of gas changes with the unit gas prices and on the gas mix actually received in the system. SoCal's customers are entitled to have any increase limited to reasonable increases in expenses actually incurred.

The staff recommendation of incorporating the trends in usage per firm customer in future filings is reasonable. We adopt the average increase in firm usage per year contained in SoCal's estimates in this proceeding, adjusted to a 30-year temperature base.

We adopt the Commission staff's recommendations as to SoCal's PGA with the exceptions discussed above. We expect SoCal to continue to participate vigorously in FPC rate, certificate, and curtailment proceedings to protect its existing gas supplies, to obtain certificates for new gas supplies, and to obtain reasonable gas rates. SoCal and/or PLS should keep the Commission staff fully informed in advance of proposed FPC filings in certificate and rate proceedings to be made by its affiliates, either acting alone or with other companies. The Commission staff should be similarly advised as to gas procurement and pricing in the California market.

Continued activity in behalf of its customers is the other side of the coin for authorization of the PGA. A SoCal witness acknowledged that such participation would present problems in a proceeding where its gas supplier was an affiliated company.

Additional R&D Requirements

SoCal witness Hill sets forth the company's policy regarding licenses and patents relating to R&D and activities entered into by SoCal as follows:

"Q Mr. Hill, a number of questions have been raised regarding Southern California Gas Company's policy relating to licenses and patents which may result from research and development.

"Would you comment on this?

"A The Examiner's question at transcript page 319 and the questions of others seem to anticipate that there may be substantial revenue benefits flowing to Southern California Gas Company from research and development programs of SoCal.

"That may or may not be the case in the future, but it has not been true to date.

"Our research program is aimed at bringing about improvements in equipment and programs which will increase our operating efficiency, make improved appliances and equipment available to our customers, conserve energy and assist in pollution abatement.

"Revenue benefits from licenses and patents, in our judgment, likely will be the least of the benefits of research and development to Southern Californians.

"Now, when employees bring developments of interest to the company we help them perfect their rights in exchange for shop rights.

" In case no manufacturer is found for such tools and devices, the gas company makes such tools and devices for its own use. When manufactured, our shop rights enable us to obtain a lower purchase price.

" The Examiner's question was directed specifically to revenue benefits from licenses and patents as related to the affiliates of Southern California Gas Company, the employees of the company and the flowing back of financial benefits from rights held by the company.

"The general policy which has been followed by Southern California Gas Company in the case where company research and development leads to an item which has possible commercial value is for the company to sell or license such development to a third party in return for royalty payments.

"In such event, the third party, whether an outside company or an affiliate of Southern California Gas Company, pays the cost of any additional development needed plus the item.

"The payments received from this arrangement are credited to operating revenues, and this is PUC Account 495, Other Gas Revenues, and thus reduce the total cost of service.

"In no instance has a product been of such value that a sale of the right itself has been made.

"In certain cases because of cost factors or lack of market interest it has not been feasible to insist on royalty payments, even though we believed the product to be of benefit to customers.

"In such cases licenses to manufacturers have been granted without the requirement to pay royalties.

"A specific instance of this situation is the recent development of the low NO_x water heater which the company believes to be immensely important to its customers but which manufacturers were not willing to pay a penny for because of the intensity of cost competition in the water heater business."

In regard to inclusion of R&D expenditures as expenses for ratemaking purposes we have previously noted: the opposition to allowing such R&D expenditures; the questions raised as to the amortization of programs; and the reasonableness of the inclusion of new projects devoted to developing new uses for natural gas.

Based on the foregoing considerations we will order SoCal to keep the Commission staff fully informed, in advance, of contemplated new R&D projects. SoCal should also supply updated information on ongoing R&D projects.

Findings of Fact

1. SoCal requests a general increase in rates of $53,151,000 above the rates in effect on February 15, 1973 in its application. During the course of the hearings SoCal made certain changes in its estimated operating results reducing its estimated revenue requirements by approximately $2,392,000, including an alternate treatment of GEDA charges. It is reasonable to consider increases in SoCal's revenue requirement to offset higher net plant budget expenditures of approximately $6,300,000 above those contained in its application for the consolidated operations of SoCal and PLS and higher expenses than those incorporated in its application, namely:

(a) $89,000 for increases in social security taxes;

(b) Sales tax increases, $640,000 on an annualized basis, $480,000 for nine months beginning on April 1, 1974;

(c) Increases postal rates, $900,000 for full year 1974 (the increases were deferred to March 2, 1974); and

(d) Increased research and development expenses of $1,000,000.

It is reasonable to decrease expenses based upon updated reduced ad valorem tax payments.

2. Prior to this proceeding the operations of the PLU system were last exhaustively analyzed by the Commission in Application No. 52696. Decision No. 80430 was issued thereon August 29, 1972. The test year used was 1972.

3. The year 1974 is reasonable and appropriate to serve as the test year in this proceeding.

4. The adopted estimates in Tables 1 and 3 of operating revenues, operating expenses, and rate bases of SoCal and PLS for 1974 test year sales of 782,850 M^2cf of gas are appropriate to determine SoCal's gross revenue deficiency under present rates and should be used for that purpose. Present rates are defined for purposes of this order as those effective as of February 15, 1973, reduced by 0.023 cents per therm which are now part of the GEDA charge, and excluding all tracking, offset, and other GEDA charges which have occurred since that date. These tables include expenses attributable to the Aliso Canyon Storage Field and the rate base, including interest during construction for test year 1974, attributable to Aliso on an as-expected basis.

5. An allowance of $8,746,000 for SoCal's 1974 sales expense is reasonable. Of this amount $2,800,000 is reasonable for informational advertising to instruct users in the efficient and effective use of gas. In A & G expenses, $650,000 is a reasonable allowance for informational advertising.

6. SoCal's earnings under present rates from its operations during the 1974 test year produce a rate of return of 6.69 percent on a rate base of $826,090,000.

7. A rate of return of 8.50 percent for the PLU system is reasonable. A corresponding return on common equity under the adjusted capital structure would be 12.35 percent. This rate of return determination is based upon imputing PLC preferred stock to PLU and the use of year-end capital ratios as described in the foregoing opinion.

8. A fixed rate of return for PLS for application in its cost of service tariff of 8.50 percent on its rate base of $197,919,000 is reasonable.

9. 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.

10. SoCal is entitled to increases of $14,799,000 in net annual revenues to raise its test year rate of return from the present 6.69 percent to the 8.50 percent hereinabove found to be reasonable.

11. An increase of $33,693,000 in annual gross revenues based upon the test year 1974 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 $33,693,000 based upon the test year.

12. The amount of the authorized increases consists in part of an estimated increase in wage and fringe benefits of 5-1/2 percent beginning on April 1, 1974. SoCal should inform this Commission of the outcome of its 1974 wage and benefit negotiations. To the extent that the expensed wage and fringe benefit increase effective on and after April 1, 1974 is below a 5-1/2 percent annual rate, SoCal should file tariffs with a uniform percentage decrease from those authorized in Ordering Paragraph 1 herein to absorb the difference between a 5-1/2 percent increase and the wage and benefit increase agreed to by it.

13. All classes of service should bear a portion of the required revenue increase of $33,693,000. Table 5 of the foregoing opinion shows the amount of increase authorized herein, by class of service. The rates authorized by this Commission, set forth in Appendix B hereto, reflect a fair and reasonable apportionment of the authorized increase in gross revenues of $33,693,000 to the various classes of service. The rates contained in Appendix B incorporate the net authorized changes in SoCal's tracking, offset, and GEDA charges from those included at present rates to June 30, 1974.

14. It is fair and reasonable:

(a) To structure interruptible rates so that no rate is below the average cost of gas and to give consideration to levels of service anticipated under the various interruptible schedules.

(b) To consolidate SoCal's firm schedules by eliminating Schedules G-20 and G-40. Such customers may continue to receive service under the appropriate general service rate schedule.

(c) To lessen the air-conditioning incentive in SoCal's rates.

(d) To not modify the G-60 rate structure absent an evidentiary showing.

(e) To increase G-30 rates above the average percentage of firm customers. We would entertain a request by SoCal on a future GEDA filing to include the G-30 schedule in a manner similar to that incorporated in the PGA.

(f) To modify rates in accordance with the criteria set forth in the opinion herein.

15. The multiplicity and magnitude of filings for gas rate increases by the suppliers of SoCal and PLS justify Commission authorization of a PGA procedure for SoCal and PLS which provides for the expeditious handling of advice letter filings relating to such increases. The PGA procedure which is adopted by the Commission in this proceeding does not authorize a rate increase at this time but provides a procedure whereby SoCal may file advice letters, which if approved will authorize rate changes in the future. SoCal and/or PLS should file an application for authorization to add costly new increments to their basic gas supply.

16. The Commission on its own motion or on the basis of a protest filed with the Commission may set for public hearing a proposed increase contained in an advice letter which is filed pursuant to the PGA procedure authorized in this proceeding. The PGA procedure authorized in this proceeding is not unjust, unreasonable, and discriminatory.

17. The PGA procedure authorized in this proceeding provides for a review of an increase proposed in an advice letter filing. The conditions and limitations of the numbers of PGA filings and the amounts to be included in the PGA filing set forth in Exhibit 1 should be modified to conform to the criteria set forth in the opinion herein.

18. The PGA tariff changes should be included in each rate schedule and explained in detail in the preliminary statement and Rule 2.

19. The proposal of SoCal relating to reduction in the PGA value and the handling of refunds is reasonable. The contingent refund dockets should be listed in Section H of SoCal's Preliminary Statement in a manner consistent with the listings now filed for offset and tracking increases.

20. The PGA increases should be spread on a uniform cents per thermal unit or an equivalent basis for Schedule G-30 using the procedure set forth in Exhibit 40.

21. Applicant files temperature adjusted operating reports with this Commission. The use of a 30-year temperature base for such reports, including reports related to PGA filings, is reasonable.

22. The Phase I proceedings were necessary to arrive at the required additional revenues to yield a reasonable rate of return for SoCal and PLS based upon existing interruptible service priorities. Possible further rate modifications and environmental considerations should be dealt with in a separate Phase II proceeding.

23. Special rate considerations for minor items, such as allocations of unaccounted for gas expense and uncollectible expense, would constitute an undesirable precedent leading to a proliferation of special rate schedules.

24. SoCal should be ordered to keep the Commission staff fully informed in advance of contemplated new R&D projects. SoCal should also supply updated information on ongoing R&D projects.

25. SoCal and PLS should be ordered to notify the Commission staff by letter of intent of planned reclassification of properties from operative to nonoperative status having book values for land in excess of $100,000. The letter should set forth the proposed accounting treatment and the reasons for the reclassification. If the property is to be conveyed to an affiliate the proposed disposition of the property should be explained. A letter of intent should be filed at least 20 days before the proposed reclassification.

26. SoCal and/or PLS should be ordered to keep the Commission staff fully informed in advance of proposed FPC filings and certificate and rate proceedings to be made by its affiliates, either acting alone or with other companies. SoCal should also advise the Commission staff about its gas procurement and costs in the California market.

Conclusions

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, providing that the expense wage and fringe benefit increase effective on and after April 1, 1974 is equal to 5-1/2 percent.

3. SoCal should file an informational filing concerning expense wage and fringe benefit increases for 1974. If the increase on and after April 1, 1974 is below 5-1/2 percent, a substitute tariff filing should be made.

4. SoCal should be authorized to incorporate its proposed PGA provision in its tariffs, modified to conform to the criteria set forth in the opinion herein. The justification for inclusion of any costly new increments of gas supply should be incorporated in a certificate application.

5. SoCal and PLS should file temperature adjusted data using a 30-year base.

6. The Phase I proceedings were necessary to arrive at the required additional revenues to yield a reasonable rate of return for SoCal and PLS based upon existing interruptible service priorities. Possible further rate modifications and environmental considerations should be dealt with in a separate Phase II proceeding.

7. Special rate considerations for minor items, such as allocations of unaccounted for gas expense and uncollectible expense, would constitute an undesirable precedent leading to a proliferation of a special rate schedules.

8. SoCal should be ordered to keep the Commission staff fully informed in advance of contemplated new R&D projects. SoCal should also supply updated information on ongoing R&D projects.

9. SoCal and PLS should be ordered to notify the Commission staff by letter of intent of planned reclassification of properties from operative to nonoperative status having book values for land in excess of $100,000. The letter should set forth the proposed accounting treatment and the reasons for the reclassification. If the property is to be conveyed to an affiliate the proposed disposition of the property should be explained. A letter of intent should be filed at least 20 days before the proposed reclassification.

10. SoCal and/or PLS should be ordered to keep the Commission staff fully informed in advance of proposed FPC filings and certificate and rate proceedings to be made by its affiliates, either acting alone or with other companies. SoCal should also advise the Commission staff about its gas procurement and costs in the California market.

ORDER ON PHASE I

IT IS ORDERED that:

1. Southern California Gas Company is authorized to file the revised tariff schedules with changes in rates, charges, and conditions as set forth in Appendix B attached hereto, and concurrently to cancel its present schedules for gas service. Such filing shall comply with General Order No. 96-A. The effective date of the new and revised tariff sheets shall be one day after the date of filing. The new and revised schedules shall apply only to service rendered on and after the effective date thereof.

2. Southern California Gas Company shall file a statement with this Commission setting forth the wage salary and fringe benefit increases granted to its employees. To the extent that this increase is less than 5-1/2 percent Southern California Gas Company shall file substitute rates reducing those authorized in Ordering Paragraph 1, herein, consistent with our findings and conclusions.

3. Southern California Gas Company is authorized to file with this Commission on or after the effective date of this order a revised Preliminary Statement and a revised Rule 2 describing a purchased gas adjustment clause in its tariffs, which incorporates the criteria set forth in the opinion herein. Such filing shall comply with General Order No. 96-A. The effective date of the revised tariff schedule shall be ten days after the date of filing. The revised tariff schedule shall apply only to service rendered on and after the effective date thereof.

4. Southern California Gas Company and/or Pacific Lighting Service Company shall keep the Commission staff fully informed, in advance, of proposed FPC filings, in certificate and rate proceedings to be made by its affiliates, either acting alone or with other companies. The Commission staff shall be similarly advised about its gas procurement and cost in the California market.

5. Southern California Gas Company is ordered to keep the Commission staff fully informed, in advance, of contemplated new research and development projects.

6. Southern California Gas Company and/or Pacific Lighting Service Company shall notify the Commission staff in advance by letter of intent of planned reclassification of properties with book values for land in excess of $100,000 in time for the Commission to determine if it has any objections to the reclassification.

7. Southern California Gas Company and/or Pacific Lighting Service Company shall file temperature adjusted reports using a 30-year base.

The effective date of this order is the date hereof.

Dated at San Francisco, California, this 16th day of JULY, 1974.

Vernon L. Sturgeon
President

William Symons Jr.

Commissioners

APPENDIX A

List of Appearances

Robert Salter and E. R. Island, Attorneys at Law, for applicant.

Arthur T. Devine, Deputy City Attorney, for Department of Water and Power, City of Los Angeles; Burt Pines, City Attorney, by Charles W. Sullivan, Attorney at Law, for the City of Los Angeles; Robert W. Russell, Chief Engineer and General Manager, by Kenneth E. Cude, for Department of Public Utilities and Transportation, City of Los Angeles; Robert J. Logan, Attorney at Law, and Manley W. Edwards, Utility Rate Consultant, for the City of San Diego; A. W. Schafer, for the City of Burbank, Public Service Department; John T. Healy, for Pasadena Water and Power Department; K. L. Parker, Principal Mechanical Engineer, for the City of Glendale, Public Service Department; Rollin E. Woodbury, Robert J. Cahall, H. Robert Barnes, Attorneys at Law, Larry R. Cope, Engineer, for Southern California Edison Company; Renn C. Fowler, Attorney at Law, for Office of General Counsel, Regulatory Law Division, General Services Administration; Chickering & Gregory, Sherman Chickering, C. Hayden Ames, Donald J. Richardson, Jr., by Donald J. Richardson, Jr., and David A. Lawson, and Gordon Pearce, Attorneys at Law, for San Diego Gas & Electric Company; William L. Knecht, Attorney at Law, for California Farm Bureau Federation; Henry F. Lippitt, II, Attorney at Law, for California Gas Producers Association; Brobeck, Phleger & Harrison, by Robert N. Lowry, Attorney at Law, for California Manufacturers Association; John B. Brewer, for Hospital Council of Southern California; Roy A. Wehe, Consulting Engineer, Edward C. Wright, General Manager, Leonard L. Putnam, City Attorney, by Harold A. Lingle, Deputy City Attorney, for the City of Long Beach; C. H. Fuller, Jr., for California Coin Laundry and Dry Cleaning Owners; Edward A. Boehler, for California Ammonia Company; interested parties.

Janice E. Kerr, Attorney at Law, Colin Garrity, and Kenneth K. Chew, for the Commission staff.

RATES - SOUTHERN CALIFORNIA GAS COMPANY

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

RATES AUTHORIZED INCLUDING TRACKING OFFSETS AND GEDA
INCREASES PRIOR TO JULY 1, 1974

ALSO A .023 CENT GEDA INCREASE AUTHORIZED
PRIOR TO FEBRUARY 15, 1973

GENERAL NATURAL GAS SERVICE

Blocking above 1,000 thermal units are consolidated into a single block. Eliminate G-20 and G-40. These customers to be billed on the General Natural Gas Service Schedules.

RATES

Commodity Charge:	Per Meter Per Month				
	G-1	G-2	G-3	G-4	G-5
Regular Usage:					
First 2 thermal units, or less	$ 3.25	$ 3.30	$ 3.35	$ 3.45	$ 4.35
Next 28 thermal units, per unit	10.207¢	10.449¢	10.965¢	11.841¢	13.353¢
Next 970 thermal units, per unit	9.213	9.613	10.029	10.527	10.998
Over 1,000 thermal units, per unit	8.608	8.608	8.608	8.608	8.608
Minimum Charge:					
All customers except "space heating only"	$ 3.25	$ 3.30	$ 3.35	$ 3.45	$ 4.35
Space heating only customers:					
November through April	$ 6.50	$ 6.60	$ 6.70	$ 6.90	$ 8.70
May through October	None	None	None	None	None

OPTIONAL RESIDENTIAL GENERAL NATURAL GAS SERVICE

SCHEDULE NO. G-10

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	$2.25	13.778¢
In rate areas where Schedule G-2 applies	2.30	14.020¢
In rate areas where Schedule G-3 applies	2.35	14.536
In rate areas where Schedule G-4 applies	2.45	15.412

MULTI-FAMILY AND MILITARY NATURAL GAS SERVICE G-20

APPLICABILITY

Schedule discontinued as of the effective date of the order herein. All customers to be billed on the appropriate General Natural Gas Service Schedules.

STREET AND OUTDOOR LIGHTING NATURAL GAS SERVICE

Schedule G-30 is subject to tracking type increases as of the effective date of the order herein.

STREET AND OUTDOOR LIGHTING NATURAL GAS SERVICE

RATES

Rate "X" -- Lighting Service only Hourly lamp rating:	Per Lamp Per Month G-30
1.99 cubic feet per hour or less	$1.32
2.00 - 2.49 cu.ft. per hour	1.64
2.50 - 2.99 cu.ft. per hour	1.92
3.00 - 3.99 cu.ft. per hour	2.22
4.00 - 4.99 cu.ft. per hour	2.52
5.00 - 7.49 cu.ft. per hour	2.88
7.50 -10.00 cu.ft. per hour	3.36
Over 10.00 cu.ft. per cu.ft., per hour	0.42

FIRM INDUSTRIAL NATURAL GAS SERVICE G-40

APPLICABILITY

Schedule discontinued as of the effective date of the order herein. All customers to be billed on the appropriate General Natural Gas Service Schedules.

SPECIAL RATES FOR AIR CONDITIONING USAGE SCHEDULES G-1 THROUGH G-5

Air Conditioning Usage:	Per Meter Per Month May Through October
First 100 thermal units, per unit	8.608¢
Next 150 thermal units, per unit	7.768
Next 250 thermal units, per unit	7.247
Next 1,500 thermal units, per unit	6.818
Next 8,000 thermal units, per unit	6.424
Over 10,000 thermal units, per unit	6.308

GAS ENGINE NATURAL GAS SERVICE

RATES

Commodity Charge:

	Per Meter Per Month G-45
First 2,000 thermal units, per unit	8.417
Next 8,000 thermal units, per unit	7.576
Over 10,000 thermal units, per unit	7.182

INTERRUPTIBLE NATURAL GAS SERVICE

SCHEDULE NO. G-50

RATES

Blocking and Rates are revised as follows:

Commodity Charge:

	Per Meter Per Month G-50
Regular Usage:	
First 10,000 thermal units, per unit	7.669¢
Next 20,000 thermal units, per unit	7.345
Next 170,000 thermal units, per unit	6.943
Over 200,000 thermal units, per unit	6.650
Special Rate for Air Conditioning Usage May through October	
First 2,000 thermal units, per unit	6.644¢
Next 8,000 thermal units, per unit	6.392
Over 10,000 thermal units, per unit	6.279

INTERRUPTIBLE NATURAL GAS SERVICE--Cont'd.

SCHEDULE NO. G-50T

RATES

Commodity Charge:

Regular Usage:

	Per Meter Per Month G-50T
First 440,000 therms, per therm	6.650¢
Next 660,000 therms, per therm	6.503¢
Over 1,100,000 therms, per therm	6.320¢

SCHEDULE NO. G-53T

RATES

Commodity Charge:

Regular Usage:

	Per Meter Per Month G-53T
First 440,000 therms, per therm	6.194¢
Next 660,000 therms, per therm	5.888¢
Over 1,100,000 therms, per therm	5.728¢

Special Rate for Air Conditioning Usage,
May through October:

Applicable to Schedules Nos. G-50T and G-53T :

First 11,000 therms, per therm	5.722¢
Next 11,000 therms, per therm	5.562¢

SCHEDULE NO. G-58

NATURAL GAS FUEL FOR UTILITY ELECTRIC GENERATION

RATE

The rate for all gas supplied under this schedule is 52.18¢ per million Btu.

WHOLESALE NATURAL GAS SERVICE

SCHEDULE NO. G-60

Revisedto reflect changes filed with Advice Letter No. 880 and further modified below.

RATES

Monthly Demand Charge:

Per Mcf of Daily Contract Demand at 68,000 Mcf per day	$3.2324

Commodity Charge, per therm:

Up to 42,500 Mcf on any day	4.766¢

For usage between 42,500 and 68,000 on any day:

Up to accumulated usage of 1,000,000 Mcf during contract year	6.155¢
In excess of 1,000,000 Mcf during contract year	8.459¢
Minimum Annual Charge for Additional Peaking Demand	$ 159,000*

* Includes up to 21,000 Mcf of gas taken during winter period calculated at the rate of $7.571 per Mcf or up to 63,000 Mcf calculated at the rate of $2.524 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 $45,000 per month with the December, January, February billings and at $24,000 with the March billing.

WHOLESALE NATURAL GAS SERVICE--Cont'd.

SCHEDULE NO. G-61

RATES

Monthly Facility Charge	$	97,500
Monthly Demand Charge:		
Per Mcf of Contract Daily Maximum Demand at 221,000 Mcf per day	$	1.9598
Commodity Charge, per million Btu		52.18¢
Additional Peaking Demand Gas:		
Annual Charge for Peaking Demand	$	234,000*
Commodity Charge per million Btu of Monthly Delivery		71.18¢

* Payment of annual charge for additional peaking demand shall be made at the rate of $42,000 per month with the November, December, January, February and March billings and at $24,000 with the April billing.

SOUTHERN CALIFORNIA GAS COMPANY

SUMMARY OF TRACKING OFFSETS AND GEDA RATE INCREASES BY CLASS OF SERVICE SUBSEQUENT TO FEBRUARY 15, 1973 UP TO AND INCLUDING JUNE 30, 1974

	Tracking Offset GEDA Increases 2-15-73 to 6-30-74 Inclusive	
	Thermal Unit Rates ¢/TU	Therm Rates ¢/Th
General Natural Gas Service G-1 through 5	1.234	
Gas Engine G-45	1.234	
Regular Interruptible G-50, 50T, 53T	1.234	1.234
Steam-Electric G-58		1.2337[a/]

Wholesale:	Long Beach	G-60	b
	SDG&E	G-61	c

a. Increase in G-58 = 12.337¢/M^{2}Btu

b. Increase in rates is: Commodity 1.2337¢/Therm

c. Increase in rates are: Monthly Commodity: 12.337¢/M^{2}Btu
Additional Peaking Commodity: 12.337¢/M^{2}Btu