Decision No. 91720 APR 29 1980

ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY for authority to revise its gas rates and tariffs effective January 1, 1980 under the Gas Adjustment Clause, and to change rate design.	Application No. 59249 (Filed October 31, 1979)
Application of PACIFIC GAS AND ELECTRIC COMPANY for authority to revise its gas rates and tariffs under the Gas Adjustment Clause to reflect increased gas costs. (Gas)	Application No. 59406 (Filed January 28, 1980)

(See Decision No. 91336 for appearances.)

Additional Appearances

Lynda Laird Weisberg, for Stanford University; Vaughan, Paul & Lyons, by John G. Lyons, Attorney at Law, for Port Costa Products Company; and Douglas Porter, Attorney at Law, for Southern California Gas Company; interested parties.

Robert Weissman, for the Commission staff.

FINAL OPINION

I. Introduction

By A.59249 Pacific Gas and Electric Company (PG&E) seeks authorization to increase gas rates pursuant to its Gas Adjustment Clause by $535.7 million on an annual basis. A portion of the relief sought was included in A.58892 and A.59045 and was disposed of by D.91108, dated December 19, 1979. The remaining amount of the increase requested is $424.8 million.

Public hearing was held in San Francisco, beginning December 10, 1979, before Administrative Law Judge Patrick J. Power. The matter was submitted following 11 days of hearing, with briefs due on January 21, 1980.

By A.59406 PG&E seeks authorization to increase gas rates by about $440 million in addition to the relief requested by A.59249, to recover increased gas costs - particularly an increase in the cost of Canadian gas effective February 17, 1980. By ALJ's ruling the submission of A.59249 has been set aside and these two matters consolidated for ultimate Commission action.

Pending completion of these proceedings, PG&E was authorized an interim rate increase by D.91336, dated February 13, 1980. The amount of the interim increase was calculated to be $336,019,000, based on the staff's estimates and a balancing account undercollection updated to reflect additional undercollection accruing after the application was filed.

Further hearings were held in the consolidated proceedings, beginning February 19, 1980. After five additional hearing days the matters were submitted subject to the filing of concurrent briefs on March 12, 1980.

The first day of hearing was well-attended by the public. A number of people made statements on the record. Many letters have also been received by the Commission relating to these applications. Direct evidence was presented by PG&E and the Commission staff, California Gas Producers Association (CGPA), Canners League of California (Canners), Kerr-McGee Chemical Corporation (Kerr-McGee), California Manufacturers Association (CMA), City of Santa Clara (Santa Clara), University of California (UC), Amstar Corporation, Spreckels Sugar Division (Spreckels), Pacific Paperboard Products (Pacific), Port Costa Products Company (Port Costa) and Toward Utility Rate Normalization (TURN). Several parties participated by way of cross-examination. Briefs were filed by PG&E, staff, CMA, UC, Santa Clara, CGPA, Southwestern Portland Cement Company (SPCC), Port Costa, General Motors (GM), City of Palo Alto (Palo Alto), Southern California Gas Company (SoCal), City and County of San Francisco (San Francisco), Kerr-McGee, Southern California Edison Company (Edison) and TURN.

II. Background

Application No. 59249 was filed October 31, 1979, requesting authority to increase gas rates effective January 1, 1980 to recover purchased gas costs and PG&E's authorized gas margin. The applicant cites the following major increases in gas prices paid to its interstate suppliers: (1) an increase from $2.80 to $3.45 per Dth in the price of Canadian gas at the Canadian border that occurred November 3, 1979, (2) an increase in the price of gas from El Paso Natural Gas Company (El Paso) pursuant to El Paso's October 1, 1979 Purchased Gas Cost Adjustment provision to $1.82 per decatherm, as well as an increase in the weighted average price of California gas to $1.83 per decatherm. The amount of the relief sought was $424.8 million, based on the September 30, 1979, balancing account undercollection of $275 million. Based on the November 30, 1979, balancing account undercollection the amount sought by PG&E in A.59249 is shown in A.59406 to be about $504.7 million.

Application No. 59406 was filed January 28, 1980, requesting authority to increase gas rates effective February 17, 1980, to recover increased purchased gas costs resulting from increases in prices charged by El Paso and PGT. On January 1, 1980, El Paso increased its rate from $1.82 to $1.96 per decatherm. The PGT rate increase passes on an increase in the border export price of Canadian gas from $3.45 to $4.47 per Dth. The amount of the relief sought is about $440 million. Thus the total amount sought by PG&E in these consolidated proceedings is $945 million.

At the hearings on A.59249, staff proposed that PG&E be authorized a rate increase of $265.4 million. Based on the later balancing account balance this was increased to $336,019,000, the basis for interim relief. In A.59406 the staff recommended an increase of about $442 million, a total increase in these proceedings of $778 million.

III. Issues Presented

The major issues are the revenue requirement to be adopted and the rate design to be applied. With regard to revenue requirement, the major differences among the parties are a function of differing estimates of gas taken from various suppliers, particularly from Canada and California. With regard to rate design, the major issues relate to the continuation of this Commission's policy of setting low priority gas rates with reference to alternate fuel prices, with several parties seeking special consideration.

These issues are typical of gas offset proceedings. Several issues of the sort more generally associated with general rate case proceedings were raised on the record and will be addressed in this decision.

IV. Summary

By this decision PG&E is found to be entitled to additional revenue in these consolidated proceedings of $723.4 million. The relief authorized is $221.6 million less than requested by PG&E, and $54.6 million less than recommended by the Commission staff. The basis for the reduction is primarily the increased use of California gas and reduced takes of Canadian supplies. Further study is planned before this policy is made permanent.

Based on the sales adopted for the test year, the revenue effect of the interim increase is recalculated to yield $304.9 million. The additional increase to be spread in this final order is $418.5 million. The adopted rate design is consistent with the rate design principles announced in D.91107 and D.91108, with slight modifications and clarification. The system average increase, including the interim, is 14.3 percent over present rates. The lifeline increase is 6.8 percent.

V. Revenue Requirement

A. Gas Supply

The additional revenue required by PG&E is a function of the supply policy and estimates to be adopted for the test year 1980. The major policy question is the relative priority of gas purchases between California and Canadian suppliers. This issue was initially the source of substantial controversy between various parties. By the close of the record, it appears to have fairly well-sorted itself out.

At the outset PG&E proposed to base rates on its long-standing policy of maximizing Canadian gas purchases, husbanding California gas for the future, while using it as a valuable peaking resource. Staff proposed that California gas takes instead be maximized, but for the test year only, with time to study and consider the impact and implications. This recommendation was based on the wide disparity between California ($1.80 Dth) and Canadian($3.54 Dth) prices existing even prior to the recently increased Canadian price ($4.58 Dth).

By rebuttal testimony PG&E announced a change in its gas supply policy that simplifies the resolution of this issue:

> "...[D]ue principally to changes in the outlook for hydro availability, the large increase in the price of Canadian gas, and somewhat reduced demand for natural gas, the natural gas strategy has again been revised. This current strategy calls for maximum purchases from El Paso, continued maximum placement of California source gas, and any reductions necessary in Canadian purchases down to the minimum annual contract take required to balance with gas loads."

PG&E joins with staff in recommending that the Commission should not adopt a long-term policy of maximizing California gas purchases until the matter is more fully analyzed.

On this basis it is reasonable to adopt, for the 1980 test year, gas supply estimates based on maximum California purchases and Canadian purchases at contract minimums. It is likewise appropriate to defer consideration of long-term policy considerations.

There does remain a difference between staff and PG&E as to the actual level of deliveries to be associated with the California gas policy. PG&E cites information developed over the winter as support for the proposition that deliverability of California gas has declined significantly below levels previously estimated. Because of the decline in deliverability, "the problem of placing low-Btu California gas and to avoid the loss of El Paso gas supplies, PG&E estimates maximum purchases for 1980 at 169,740 Mdth", 31,750 Mdth lower than staff.

In light of the uncertainty of this information we conclude that the circumstances support the adoption of PG&E's estimate for the purpose of this proceeding. This does not affect the determination on the policy issue that maximum California gas should be purchased. But there is a risk associated with over-estimating the amount of California gas for this purpose - further undercollection. Therefore we determine that it is reasonable to base these rates on PG&E's estimate, with the expectation that the parties will reexamine this matter in the next PG&E gas offset proceeding.

There is also a difference between PG&E, staff and TURN as to the appropriate estimate of El Paso deliveries to be adopted for this proceeding. The respective estimates are as follows:

PG&E	296,363
Staff	315,445
TURN	335,811

From among these estimates we find the staff estimate most useful for purposes of this proceeding. It is based on more current information than is PG&E's, while TURN's number is simply the recorded figure for 1979, without adjustment for weather or the operation of El Paso's curtailment plan. The staff estimate does not include additional supplies available to El Paso from time to time in unpredictable quantities, through short-term contracts under Section 311(b) of the Natural Gas Policy Act (NGPA), and is characterized as the minimum quantities available during the forecast period. This is a reasonable basis for setting rates in view of the relatively favorable hydro conditions likely to prevail for the test year and the additional undercollection that would occur if the supply level adopted is higher than recorded.

The other area of dispute relates to the amount of gas withdrawn from storage during the test period. The staff brief recites the facts and offers a well-reasoned analysis:

"The third difference in supply estimates involves withdrawals of gas from the Coalinga Nose storage field. The staff's estimate of 18,360 Mdth exceeds PG&E's projection of 779 Mdth by 17,581 Mdth. PG&E's potential for withdrawals from Coalinga is controlled by an injunction committee which supervises the production of oil and withdrawal of gas from the field. PG&E was allowed to withdraw approximately 50 Mcf per day during November and December, 1979. The staff's projection of 18,360 Mdth assumes PG&E will continue withdrawals at this rate during 1980. PG&E's estimate assumes no withdrawals from Coalinga during the forecast period.

"The staff's estimate is more reasonable because PG&E currently has the right under contract to withdraw gas from Coalinga. During January and February, 1980, PG&E is being allowed to continue withdrawals of up to 50 Mcf per day. Presumably this condition will continue throughout 1980. The potential for future limitations set by the injunction committee makes it imperative that PG&E withdraw out of Coalinga all the gas it can take at a reasonable rate rather than risk having it shut in. Since PG&E currently has the contractual right to withdraw gas and because it would be prudent for the applicant to withdraw gas as quickly as allowed by the injunction committee, the staff's projection is superior to PG&E's estimate of no withdrawals from Coalinga."

We find the staff position to be reasonable and adopt it for the purposes of this proceeding.

Based on the foregoing, PG&E's test period cost of gas for ratemaking purposes is as follows:

TABLE 1

Cost of Gas
Test Year 1980

Source	Supply (Mdth)	Price ¢/Dth	Cost (M$)
California	169,740	180.31	$306,058
El Paso	315,445	195.67	617,231
PGT-Canadian	331,588	458.06	1,518,872
PGT-Rocky Mountain	4,015	153.63	6,168
Subtotal Purchases	820,788	298.29	2,448,329
Withdrawal	18,360	106.13	19,485
Injection	(9,976)	298.29	(29,757)
Total	829,172	294.04	2,438,057

(Red Figure)

B. Balancing Account

In order to calculate PG&E's gross revenue requirement, it is necessary to add to the cost of gas the balancing account undercollection, an adjustment for franchise fees and uncollectibles, and the gas department margin found reasonable in PG&E's most recent general rate case, D.91107, dated December 19, 1979, in A.58545/6. Of the adjustments, the only issue among the parties is the balancing account balance to be applied.

At the time of the application PG&E based its request on the recorded balance in its balancing account of $275,015,000, as of September 30, 1979. By subsequent exhibit it updated the record to include its recorded balancing account balance as of November 30, 1979, which is $345,699,000. This is unaudited, but no party objects to the use of the more current balancing account information in these proceedings, as long as it is understood that such use is subject to later audit.

Staff does propose two adjustments to the balancing account, relating to the accounting treatment of sales of gas by PG&E to SoCal, and certain amortization charges on odorizing facilities. The effect of these adjustments is to reduce the balancing account balance by $5,214,000 to $340,485,000.

By far the larger part of the adjustments (over $5 million) relates to the issue of the accounting treatment. This issue is summarized in the following excerpt from staff witness Pulsifer's testimony:

> "In PGandE's pending Application No. 58892, filed May 25, 1979, requesting an increase of approximately $274 million in gas rates, the staff accountant took exception to PGandE's accounting treatment for recovery of carrying costs on gas withdrawn from storage and sold to SoCal. PGandE recorded a portion of the sales revenue received from SoCal in Account No. 495 - Miscellaneous Gas Revenues. This revenue, in the amount of $4,317,000, representing the carrying costs on gas withdrawn from storage, was not credited to the SAM account. This issue is still pending as of this current proceeding.
>
> "The staff accountant recommended in Application No. 58892 proceedings that such revenues should be credited to the SAM Balance Account in order to state properly the undercollection in the authorized test-year margin. The basis for the staff accountant's exception to PGandE's accounting treatment of revenues related to SoCal sales withdrawn from gas storage is that PGandE excluded from the SAM account revenue representing the gross margin earned on the gas sales withdrawn from storage. The gross margin earned by PGandE on such sales equaled $0.45 per decatherm sold. Since this revenue contributed to the overall gross margin earned by the Gas Department, and since it was the direct result of a change in sales volume, it is the staff accountant's opinion that the gross margin revenue of $0.45 per decatherm earned on SoCal sales should be included in determining the recovery of the authorized test-year gross margin. PGandE's method which excluded this gross margin revenue from the SAM account understated the recovery of the test-year margin.

> "PGandE's position with respect to its accounting treatment of SoCal sales revenue is set forth in Advice No. 1019-G, dated December 18, 1979. PGandE intended that the gross margin revenue of $0.45 per decatherm of sales from storage would be used to recover carrying costs on gas withdrawn from storage not otherwise recoverable through base rates.
>
> "It is the staff accountant's opinion that PGandE's method of recovering carrying costs on gas inventory in excess of base rate recovery constituted a 'rate adjustment relating to rate base items' as described in Decision No. 90424, dated June 19, 1979, in Applications Nos. 58469 and 58470. According to that decision, rate adjustments relating to rate base items should only be considered together with overall test-year earnings in a general rate proceeding to avoid unbalancing customer and investor interests. Accordingly, the staff accountant recommends that SoCal gas revenues recorded in Account 495 should be included in the SAM account. As of September 30, 1979, the GCBA undercollection should be reduced by $4,452,000 including interest of $195,000 in order to recognize the recovery of the test-year margin resulting from SoCal sales withdrawn from storage."

PG&E argues that it is appropriate that it recover the carrying costs on its excess gas from a third party (SoCal) since it was unable to recover such costs from its ratepayers. This argument is without merit.

PG&E's argument proceeds from a false premise. In contending that because recorded carrying costs exceed test year estimates it has not been compensated it ignores basic regulatory principles.

The prospect that recorded levels will be more or less than test year levels is a risk or opportunity for the utility that is taken into consideration in determining a reasonable rate of return in a general rate case. There is no relevance to an isolated single year comparison on either side of the equation. PG&E has been "compensated" for the <u>risk</u>. We agree with

Mr. Pulsifer that PG&E's treatment is analogous to the rate base offset adjustment that was previously rejected in D.90424.

PG&E's method also appears unreasonably arbitrary. The notion that stored gas is sold to SoCal, while flowing gas is sold to its own ratepayers, is apparently supported only by the intended result - that is, it is a fiction with no purpose other than to justify the ratemaking treatment. If we adopt PG&E's method, then it is necessary to consider whether it should have left the gas in storage for its own ratepayers and cut back on Canadian deliveries. Mr. Pulsifer's ratemaking treatment is reasonable and should be adopted.

Staff's other adjustment relates to a charge of $1,082 per month included by PG&E as a component of its PGT cost of gas. The charge is attributable to cost recovery for facilities in Malin, Oregon, used to control the odorant level of PGT gas. Staff takes exception to the inclusion of these charges on the ground that they are fixed in nature and bear no direct relationship to the cost of purchased gas. We agree with staff as to the appropriate treatment of these charges, and observe that, although the specific dollar amount is minor, the principle is important and may be a precedent in future proceedings.

The adopted balance, $340,485,000, includes an adjustment to reflect approximately $67.1 million for supplier refunds previously credited to the balancing account. The California Supreme Court in California Manufacturers Association v Public Utilities Commission (1979) 24 Cal 3d 836 reversed this Commission's treatment and required that refunds be made. A refund plan has been approved. PG&E asks that it be authorized to collect these revenues so that refunds may follow. TURN proposed that collection of the revenues be deferred.

We find that it is reasonable to provide for the recovery of the money to be refunded in this proceeding. PG&E's substantial undercollection and the high interest rates make delay of recovery unreasonable. Unnecessary delay in making the refunds is undesirable,[1] in light of the Supreme Court's determination that refund shall be made.

C. Gross Revenue Requirement

Based on this discussion, PG&E's gross revenue requirement is derived as follows:

TABLE 2

Gross Recovery Amount

Current Cost of Gas	$2,438,057
Gas Cost Balance Account	340,485
Subtotal	2,778,542
Adjustment for Franchise Fees and Uncollectibles	26,535
Base Cost Amount	536,865
Total	3,341,942

The additional revenue required to attain this gross recovery amount may be calculated by comparing the revenue produced by test year sales at current rates with the gross amount required. For purposes of this calculation PG&E's estimate of sales to customer classes is adopted, with the assumption that gas supplies exceeding PG&E's test year estimate will be sold to PG&E's electric department on the G-55 schedule.

1/ A refund plan has been approved by Resolution No. G-2343 on April 15, 1980.

TABLE 3

Adopted Sales

Customer Class	Sales (Mth)	Present Rate (Without Interim)	Revenue (M$)
Residential			
Customer Months	32,279	$1.20	$38,735
Tier I	1,704,829	23.373	398,470
II	503,880	40.466	203,900
III	135,831	50.014	67,935
	2,344,540		709,040
Nonresidential			
G-2 Customer Months	2,059	1.20	2,471
Commodity	1,789,980	34.841	623,647
G-50	863,520	40.062	345,943
G-52	697,200	34.062	237,480
G-55	1,775,050	30.062	533,616
G-57	136,970	36.109	49,458
	5,262,720		1,792,615
Resale			
G-60 LL	15,367	22.138	3,402
G-60 NLL	30,233	27.656	8,360
G-61 LL	2,016	22.091	446
G-61 NLL	1,724	27.614	476
G-62 LL	462	22.091	102
G-62 NLL	728	27.614	201
G-63 LL	21,560	22.091	4,763
G-63 NLL	31,720	27,614	8,759
	103,810		26,509
SoCal Gas	295,650	30.559	90,348
	8,006,720		2,618,512

TABLE 4

Gross Additional Revenue

Gross Recovery Amount	$3,341,942,000
Revenue at Present Rates	- 2,618.512,000
	723,430,000

The gross additional revenue represents the amount to be authorized in these consolidated proceedings. Based on the adopted sales levels, the amount of revenue yielded by the interim increase must be recalculated; at 3.808 cents per therm the revenue effect is $304,896,000. Thus the additional increase to be spread in this final order is $418,534,000.

D. Prudency

There was one other issue raised with respect to revenues - TURN's proposed "prudency test". As stated by TURN's witness, Dr. David S. Schwartz, the substance of the proposal is as follows:

> "I recommend that the Commission require PG&E to reduce their Canadian volumes to 90% of contract obligation and substitute domestic natural gas. At a minimum the Commission should require PG&E to continue its gas purchases from El Paso at the 1979 level of 335,811 Mdth. In addition, I recommend that the Commission require PG&E to demonstrate in future applications to increase rates under the gas adjustment clause that they have procured the lowest cost available gas supply. If the Commission finds that PG&E has not obtained the lowest cost available gas supply, then a reduction should be reflected in purchased gas cost based upon a prudency judgment by the Commission."

These points are elaborated upon further by TURN in its brief, wherein 5 specific provisions are proposed:

> "1. Any discretionary Canadian purchases will be deemed imprudent if domestic gas is available as a cheaper substitute.
>
> "2. A discretionary Canadian purchase will be deemed imprudent if it results in additional sales to G-55 at a time when fuel oil is available to PG&E at a cheaper price.
>
> "3. A discretionary Canadian purchase will be deemed imprudent if it results in additional sales to G-55 and the underlift or storage of contract fuel oil at a time when that fuel oil is cheaper than the combined cost of Canadian gas plus the underlift or storage charge.

"4. If discretionary Canadian gas is purchased and the result is additional sales to G-55 at a rate less than the cost of Canadian gas, the cost differential between the Canadian price and the G-55 rate will be disallowed as a gas department expense and imputed as an electric department expense.

"5. PG&E shall be ordered to attempt renegotiation of the contracts between Alberta and Southern and the Canadian gas producers in order to provide flexibility for purchases below the 90% level without take-or-pay penalties. PG&E should report on the progress of these negotiations in each GAC application."

PG&E objects to TURN's proposal as unreasonably rigid and destructive of its needed flexibility to adjust for changing conditions. It contends that as a combination gas and electric utility, it has an obligation to secure the most economic mix of total energy supplies consistent with preserving its ability to provide reliable service. It characterizes TURN's proposal as addressed to gas purchases as they apply to gas rates in isolation. PG&E asserts that as a combination utility it cannot and should not purchase natural gas from such a limited perspective. Instead, systemwide demand should be taken into consideration and a comprehensive fossil fuel procurement strategy designed, while the utility constantly evaluates factors and remains flexible.

We agree with PG&E that the specific prudency standards proposed by TURN are too rigid to be adopted in this proceeding on a formula basis for the 1980 test year. But in view of the significance of these issues and the expectation that prudency will emerge as an issue in subsequent proceedings, it is appropriate that this Commission offer certain guidelines by way of comments.

A prudency test is implicitly present in any rate proceeding. Only costs prudently incurred may be recovered from the ratepayers. In offset proceedings this test necessarily requires an estimate of reasonable expenses for the test year, and an examination of the reasonableness of recorded expenses included in the balancing account. The test year estimate does not amount to a determination of the reasonableness of the associated procurement strategy.

So it is that the adopted sales estimates in this decision do not operate as a substitute for PG&E's obligation to prudently manage its gas supply resources. The use of the Canadian contract minimums for setting rates does not conclusively indicate that purchases in excess of the minimum are imprudent; neither does it indicate that purchases up to the minimum are prudent. It is merely a reference point for setting rates.

The basic prudency test is economic - if the gas may be sold for more than it is bought for, then the purchase was plainly prudent. But there may be any number of circumstances that support the purchase of gas where the simple economic test cannot be met. In these cases the burden of proof is on the utility to justify its procurement strategy.

The ratemaking choices are to allow the dollars to be recovered, to disallow the dollars, or to allow recovery, but in a subsequent general rate case proceeding.

As regards the specific facts of this case, we decline to go as far as proposed by TURN and "require" that PG&E reduce its takes of Canadian gas to the minimum contract level. But we are concerned that the availability of offset relief dampens PG&E's incentive to minimize its Canadian gas costs, and in future proceedings it will not be sufficient justification on PG&E's part that the volumes purchased are the minimums in the contracts.

Up to this point the "take or pay" provisions in PG&E's export agreements have been taken as a given, largely because the anticipated decline in El Paso deliveries left a sense of inevitability to the continued reliance on Canadian supply. But the combination of circumstances likely to prevail during the test year - maximum

California deliveries, continued high El Paso deliveries, and abundant hydro, could produce the previously unlikely situation that even the contract minimums are not required. In this context without offset relief we would expect to see PG&E undertake some effort to reduce its Canadian obligation through renegotiation of its contracts or otherwise. The mere availability of offset relief does not alter our expectations.

One additional matter merits discussion in this context, that being TURN's contention that PG&E, by virtue of its corporate affiliations, may have a special interest in purchasing amounts of Canadian gas in excess of what best serves the interests of its ratepayers. TURN has failed to substantiate this contention, and what evidence is available suggests strongly that such suspicions are without merit.

Testimony taken in this proceeding and included by reference from prior PG&E gas cost offset proceedings indicates that PG&E has an ownership interest in Alberta and Southern Gas Company (A&S), which purchases gas from 80 to 100 different producers, through the Alberta Petroleum Marketing Commission, an agency of the Alberta government. A & S pays certain transportation charges, and resells the gas at the U.S.-Canadian border to Pacific Gas Transmission Company (PGT), which transports the gas to the California-Oregon border where it is resold to PG&E. PG&E also has ownership interests in PGT and in Alberta Natural Gas Company (ANG), a pipeline company which provides transportation across British Columbia for the gas owned by A & S. The evidence demonstrates that the revenues of each of these three PG&E affiliates-A & S, ANG, and PGT-are determined on a cost of service basis, providing for the recovery of their costs of operations plus a specified return on capital investment, as determined by the jurisdictional regulatory agency, either a Canadian government agency or, in the case of PGT, the FERC. Thus, the earnings of these companies are unaffected by any variations in Canadian delivery volumes within the range of possibility considered in this proceeding. There is no evidence of record that PG&E has any ownership interest in any other entities associated with the chain of production or transmission of Canadian gas.

VI. Rate Design

A. Introduction

In the recently decided PG&E general rate case decision, D.91107 (A.58845/6) dated December 19, 1979, we stated:

> "The rate design principles adopted in this general rate proceeding serve as a basis for rate design in this proceeding...and in subsequent natural gas offset proceedings until a decision is issued in a subsequent general rate increase proceeding." (Mimeo. p. 137)

The specific rate design criteria adopted in D.91107 are the following:

"(a) The rate revision shall produce the total revenue requirements determined to be reasonable, based on the adopted level of sales. The increase in rates necessary to produce the total revenue requirement shall be spread in proportion to the following criteria. (The average system rate is total revenue requirement divided by the total sales.)

"(b) No increase shall be made in customer (demand) charges. Increases shall be made only in the commodity rates.

"(c) The average lifeline rate shall be 25 percent below the average system rate.

"(d) Schedule G-2 rates shall be determined in reference to the average system rate (less lifeline sales and revenues).

"(e) The Schedule G-50 rate shall be referenced to the estimated current price of No. 2 fuel oil (or at a premium above the Schedule G-52) rate).

"(f) The Schedule G-52 rate shall be referenced to the estimated current price of No. 6 low-sulphur fuel oil.

"(g) The Schedule G-55 rate shall be referenced to the current price of No. 6 low-sulphur fuel oil purchased by PG&E.

"(h) The Schedule G-57 rate shall be referenced to the current price of No. 6 low-sulphur fuel oil purchased by Edison.

"(i) Resale rates to all resale customers (excluding SoCal Gas and Palo Alto) shall be referenced to the average system cost of gas except that the quantities representing lifeline sales of each resale customer shall be 20 percent less than the nonlifeline rate.

"(j) The residential blocks shall be on an inverted rate schedule, with the last block having the highest rate. The average rate paid by a residential customer using twice the lifeline quantity should approximate the G-2 rate. The average rate for residential customers using three times the lifeline quantity should approximate the G-50 rate."

These criteria are applied herein with slight modification to reflect developments on the record.

B. Objections

Various parties object to our policy of basing rates for low priority customers on alternate fuel costs. Instead, these parties propose that rates be based on "cost of service". This is the position supported by CMA, GM, Kerr-McGee, SPCC, Spreckels, Edison, and Canners. In support of this proposition "cost of service" studies were offered by CMA and Kerr-McGee. CMA also sponsored the testimony of Dr. George Schink, who testified in favor of rolled-in, rather than incremental, gas prices. Kerr-McGee offered a package of materials from prior proceedings.

These proponents of "cost of service" insist and persist in spreading gas costs on a uniform cents per therm basis in their studies. This allocation method is unreasonable in view of the gas priority system and the different prices paid different suppliers. We find such studies to be of no probative value in setting gas rates.

Any attempt to calculate a meaningful "cost of service" must reflect the low priority status of industrial boiler fuel customers and the variable nature of gas supply. To the extent that gas supply is a function of price, the cost of gas to serve low priority customers includes not only the commodity cost of the specific gas sold to those customers, but also the incremental cost of the gas sold to high priority customers above the price that would be sufficient to produce enough supply to serve only high priority demand. This principle is crucial in analyzing the transition from a regulated to an unregulated market, as in gas supply.2/

CMA's Schink testified regarding the results of a study by Wharton Econometric Forecasting Associates, Inc. which sought to examine the "differential effects on the U.S. economy of various means of recovering the higher natural gas costs associated with the decontrol of natural gas prices." According to CMA, the results

> "lead to the conclusion that residential customers would be worse off with full implementation of incremental pricing than if it were limited to non-exempt boiler fuel customers. Further, such customers are worse off with any sort of incremental pricing than with increased gas costs simply spread uniformly over all sales."

2/ A simple illustration will demonstrate the point. Suppose that 20 therms of gas will be produced at 4¢ per therm, and that 25 therms will be produced at 5¢ per therm. The cost of the additional 5 therms is obviously not 5¢ per therm; it must include the additional 1¢ per therm paid for the 20 therms that would have been produced at the lower price. Thus the cost of the additional 5 therms is 5¢ + 20/5 = 9¢ per therm.

We find Dr. Schink's study to be of no meaningful use in this proceeding. The assumptions underlying the study are highly speculative and not particularly appropriate for California. We also have trouble reconciling his central thesis with another economic theory cited by CMA - marginal cost pricing results in the most efficient utilization of resources.

CMA warns that our rate design policy as interpreted by the staff "results in the masking of the real cost of energy to millions of residential customers. They will fail to change consumption habits and fail to purchase energy savings hardware because they have been misled concerning the true cost of natural gas". First, we conclude that the inverted rate does provide a very real signal to the residential ratepayers. Second, we see no basis for "misleading" the industrial customer regarding the "true cost" of natural gas.

The industrial customers testifying before this Commission have vividly depicted their conservation efforts resulting from the higher gas prices. This testimony indicates that the rate design has succeeded in this regard. Several have mentioned even resorting to coal, so that sales will be lost to the utility. We consider such action consistent with the national energy policy, as we understand it. Most of these customers have expressed an interest in new or additional cogeneration. We consider this an exciting expression of the validity of our rate design and point out that this is an application of "energy saving hardware" that largely eludes the residential ratepayer, no matter how high we set the rates.

We do not mean to slight the conservation potential of the residential sector, and therefore have provided steep inversion of the rates. And although staff and Dr. Schwartz agree that the lifeline sales are relatively inelastic, we think that it is likely that some conservation can be achieved within this sector of usage, so that it would be inappropriate to shield lifeline residential customers from sharing any portion of the burden of increasing gas supply costs.

There is additional evidence in the record that we find quite compelling in support of our rate design policy. This includes the statements of the National Energy Board of Canada in its January, 1980 Report to the Governor in Council announcing the increased price, and DOE/ERA Opinion and Order No. 14, authorizing the interim importation of Canadian gas at the higher price.

The National Energy Board stated the following:

> "While the general proposition is true that provided the price of Canadian gas is not higher than the marginal cost of energy to the United States as a whole (i.e., the cost of OPEC oil), markets should be available to Canadian gas, although this may not happen automatically. United States market imperfections for natural gas could slow or inhibit a rearrangement of sales of Canadian gas from those markets where it is over-priced to those where it can be sold at the going price.
>
> "On the one hand, the process is aided by the practice of rolling-in or averaging gas from different sources into a single price, but the effect of this varies from region to region depending on the proportion of Canadian gas sold. On the other hand, the process is impeded because OPEC oil is rolled-in with lower cost indigenous crude oil and the resultant price of No. 2 and No. 6 fuel oils may be less than the price of Canadian natural gas."

We see no point in aiding the Canadians in recovering their higher gas prices by "rolling-in" the price.

DOE/ERA Opinion and Order No. 14 addresses the Canadian increase and rate design in the following terms:

> "Given the substantial increase in the price of these flowing imports and the purposes that are intended to be served by incremental pricing, the public interest requires that all of that portion of Canadian gas imports

> which exceed 1977 base year volumes (as determined by the FERC) should be incrementally priced during the period that the interim approval of the new Canadian export price is in effect. Allowing the price to be rolled-in with other, cheaper domestic pipeline supplies would mask the true cost of the gas and would result, in effect, in a subsidization of the high-cost imported fuel. Such distortion would impact negatively on our overall energy policy by sending to low priority gas users a false signal as to the true cost of these supplies and postpone conversion to secure, domestic alternative fuels or other domestic sources of natural gas. Under Section 207(c)(2) of the NGPA, therefore, we conclude that the incremental pricing provisions of Title II should apply to the projects authorized today to the extent that the approved volumes exceed the respective volumes imported by the companies involved during the 1977 base year."

This language does not compel our rate design policy, but it strongly supports it. Thus we find our rate design policy consistent with national energy policy.

C. Residential Rates

The comments of the various parties suggest that the criteria relating to residential rates need to be refined. In particular there are indications that the term "average lifeline rate" in (c) is ambiguous and that the criteria for developing the tier III rate in (j) may yield a tier III rate that is lower than the tier II rate, contrary to our expressed policy that the tier III rate will be the highest rate on the system.

Staff recommends that criterion (c) be modified to reference the lifeline quantity to the winter allowance of 106 therms for zone X, and that the language be then changed to: "The average lifeline rate should approximate 78 percent of the average system rate". Basing the lifeline quantity on the winter allowance is alleged to be reasonable because the gas bills are larger and thus have the largest influence on what customers pay. The 78 percent relationship is justified as approximating the relationship of lifeline to the system average that existed when PG&E's average system rate had increased 25 percent over the January 1, 1976 level. The substitution of the term "should approximate" for "shall" is suggested to provide flexibility. PG&E supports the staff recommendation in its brief.

TURN proposes a different method, which it characterizes as simple, fair, and workable. It proposes that the adopted residential customer charge revenues be divided by the adopted total lifeline sales to yield an average cents per therm factor for the customer charge. Under TURN's proposal the sum of the average customer charge factor and lifeline commodity rate would equal 75 percent of the system average rate. It characterizes the staff method as intended simply to generate more revenue from lifeline and not fair or reasonable.

We find that the method of calculation proposed by TURN is most simple and workable and is consistent with our intention in developing the rate design criteria. The staff method is keyed to lifeline percentages as they apply to PG&E and may not be adaptable to other companies, particularly since the 78 percent factor is apparently a historical accident, depending on the extent that lifeline rates had been already implemented for a particular utility as of January 1, 1976.

With respect to the tier III rate, staff correctly points out that under the present formula the tier III rate tends to fall below the tier II rate as the average system rate approaches the G-50 rate. Staff proposes to modify the guideline to provide: "The average rate for residential customers using three times the lifeline quantity (tier III) shall be the highest system rate". The intent of the proposed modification is reasonable but would be better achieved by the following language: "The average rate for residential customers using three times the lifeline quantity shall be higher than the rate for any nonresidential customer class."

D. Alternate Fuel Price

Rate design principles (e) through (h) refer to this Commission's policy of setting rates for low priority customers with reference to the price of alternate fuel. The central issue in this regard is the interpretation of the data.

In previous cases this Commission has relied on published prices in Platt's Oilgram as the basis for its determination of alternative fuel prices for priority 3 and 4 customers. In this proceeding both PG&E and staff have offered Platt's published information, adjusted as each considers appropriate. In addition, the record contains information regarding recent prices paid by PG&E and Edison for fuel oil purchased for electric generation. The state of the record and the parties' contentions are summarized in this excerpt from PG&E's brief describing the positions of PG&E, staff, and TURN with respect to the G-52 rate:

> "The different ways PGandE, the Staff and TURN approach alternate fuel based rates can be seen most readily in the recommendations on the G-52 rate. The various rate proposals for Schedule G-52 have been based on price information for No. 6 fuel oil, the alternate fuel for Schedule No. G-52. There are two basic sources for the information-PGandE's purchases and Platt's Oilgram. PGandE's purchases of No. 6 oil are reflected in Exhibit 29. Converted to a cents per therm figure, PGandE's purchase price for December, 1979 and January, 1980 were 38.17¢ and 41.65¢ per therm, respectively. Based on the Staff's conversion method, PGandE's January 1980 purchase price for No. 6 oil was 43.66¢/therm.
>
> "The Platt's information is developed in Exhibits 39 and 44. Unlike the PGandE purchase prices, the Platt's figures for No. 6 low sulfur fuel are not based on any actual West Coast transactions involving this fuel. Indeed, Platt's does not even publish a low sulfur No. 6 price for the West Coast. Instead, Exhibits 39 and 44 develop a figure from Platt's by applying a differential between high and low sulfur No. 6 oil to Platt's published figure for high sulfur No. 6 oil on the West Coast.

> Those calculations produce prices for No. 6 low sulfur fuel oil ranging from 44 to 46¢/therm in December and January to 48.83¢/therm in February. Comparing PGandE's purchase prices to the Platt's derived figures, one quickly sees that the PGandE prices are slightly lower than the lowest comparable Platt's figure.
>
> "Given this same range for No. 6 fuel oil prices, from PGandE's purchase price of approximately 38¢ to 40¢ per therm to the high Platt's derived figure of 48.83¢ per therm, PGandE, TURN and the Staff each arrived at significantly different G-52 rate proposals. TURN recommends a rate of 45.8¢ per therm, near the upper end of the Platt's range. Staff suggests a rate of 44.2¢ per therm, setting the rate slightly below an average of the low Platt's prices for the December-January period. And PGandE arrives at a G-52 rate between 41.3¢ and 42.2¢ per therm by reviewing the range of No. 6 oil prices with special weight given to PGandE's price of No. 6 fuel oil."

We will adopt PG&E's proposal and set the G-52 rate at 42.874 cents per therm. This is a departure from our usual practice of relying on staff adjustments to Platt's data, but is justified in view of the uncertain conditions that may prevail in the oil market resulting from the expected abundant hydro power and the resulting reduced utility oil requirement.

With respect to the G-50 rate, the applicable criterion provides that the rate shall be referenced to the price of No. 2 fuel oil, or at a premium above the G-52 rate. The point of the alternative is to allow the Commission discretion to recognize the potential for induced investment when the price of No. 2 fuel oil so much exceeds the price of No. 6 fuel oil that rates set based on each would cause customers to switch fuel oil capability merely to be eligible for the lower gas rate.

The existing differential between G-50 and G-52 rates is 6¢ per therm. The differentials proposed by staff, PG&E, and TURN are 3.6¢, 7¢, and and 3¢ respectively. Based on evidence developed in the record by staff witness Miller we are concerned that the existing difference provides an undue incentive for wasteful conversions. We have previously utilized a 3¢ difference without apparent switching of capability. Therefore we adopt a 3¢ differential in this proceeding.

With respect to G-55 and G-57 schedules the criteria call for these rates to be set based on the alternate fuel prices of PG&E and Edison respectively. Staff proposed rates of 36¢ per therm and 39.97¢ per therm based on PG&E's and Edison's November fuel prices.

PG&E contends that despite the Commission's decision, low sulfur fuel oil is the wrong alternate fuel for G-57. It points out that the Coolwater plant is in an area where higher sulfur oil may be burned, and that it is essentially the same type of customer as the power plants served under G-55. Therefore PG&E recommends using the price of oil purchased by its electric department as the appropriate alternate fuel price for G-57, and proposes a 39-40¢ rate.

The original staff position in A.59249 also proposed a uniform G-55, 57 rate, but on a different basis than PG&E. Staff witness Miller characterized the purchase of gas by the electric utility as more like the purchase of spot market oil than like the long-term contract purchases which are for relatively fixed amounts. Therefore he proposed that the rate be set based on current market conditions at the same level as the G-52 rate. TURN concurs with Mr. Miller's approach and proposes a rate set at 45.55¢ per therm.

Edison objects generally to the use of alternate fuel prices in setting rates, but points out that the Commission has previously discounted its gas price to reflect various costs incurred by an electric utility in substituting gas for oil.

We find the argument of PG&E and Mr. Miller convincing. For no other customer class have we distinguished between two customers of the same industry based on different prices for the same type of fuel oil. The current market price-test proposed by Mr. Miller seems an appropriate consideration. We are also committed on an interim basis to a cogeneration incentive gas rate tied to the G-55 rate. Therefore we adopt a uniform G-55, 57 rate that provides some benefit for cogeneration.

E. SoCal Gas

In December, 1978, PG&E and SoCal entered into a contract whereby PG&E would sell to SoCal 75 Mcf of gas per day on a firm basis with the potential for an additional 75 Mcf per day of best efforts gas. Under the contract, the price paid by SoCal is to increase based on increases in PG&E's system average cost of gas. The contract was presented to the Commission and approved in Commission Resolution No. G-2259.

Staff witness Miller proposed to disregard the contract terms and establish a higher rate. The basis for his recommendation is an analysis of changing gas supply circumstances and a comparison of the rate level to the cost of Canadian gas. Staff witness Fowler proposed a rate based on the contract terms.

PG&E and SoCal oppose Mr. Miller's recommendation. PG&E asserts that the Commission lacks jurisdiction to modify the contract. SoCal argues that the matter should be considered only under circumstances in which substantial advance notice is given so that all relevant circumstances should be considered.

We agree that this matter should be examined in depth in the next PG&E gas offset proceeding and the contract terms reexamined in light of the changes in gas supply policy announced by PG&E and examined in this decision. In the interim, it is reasonable to set rates based on the contract terms, but only under the assumption that the gas supply policy has not changed. For this purpose we impute the prior supply policy proposed by PG&E and the rate resulting therefrom: 43.087¢ per therm.

F. Palo Alto Rates

Staff witness Fowler testified that the G-60 rates authorized in D.91108 were calculated on a basis differing from that found reasonable in D.89315 and D.89316 and continued in D.91108. He points out that the differential is expressed in percentage terms and in cents per therm. Maintaining the percentage differential as gas costs rise increases the cents per therm margin unreasonably. His proposed revision is reasonable and shall be adopted.

A.59249, 59406 ALJ/jn

TABLE 5

Adopted Rate Design

Customer Class	Sales (Mth)	Present Rate $/th (Includes Interim)	Revenue (M$)	Adopted Rate $/th	Revenue (M$)	% Increase
Residential						
Customer Months	32,279	$1.20	$38,735	1.20	$38,735	0%
Tier I	1,704,829	.27181	463,389	.29032	494,946	6.8
Tier II	503,880	.44274	223,088	.56705	285,725	28.1
Tier III	135,831	.53822	73,107	.66698	90,596	23.9
	2,344,540	.34050	798,320	.38814	910,002	14.0
Nonresidential						
G-2 Customer Months	2,059	1.20	2,471	1.20	2,471	0
G-2 Commodity	1,789,980	.38649	691,809	.44562	797,650	15.3
G-50	863,520	.39870	378,826	.45874	396,131	4.5
G-52	697,200	.37870	264,030	.42874	298,918	13.2
G-55	1,775,050	.33870	601,209	.40366	716,517	19.2
G-57	136,970	.39917	54,674	.40366	55,289	1.1
G-60 LL	15,367	.25946	3,987	.28032	4,308	8.0
G-60 NLL	30,233	.31464	9,513	.40350 ~~.42619~~	12,885	35.4
G-61, 62, 63 LL	24,038	.25899	6,226	.30526	7,338	17.9
G-61, 62, 63 NLL	34,172	.31422	10,738	.38178	13,046	21.5
SoCal	295,650	.34367	101,606	.43087	127,387	25.4
	5,662,180		2,125,088		2,431,940	
Total	8,006,720	.36512	2,923,408	.41739	3,341,942	14.3
Total NLL	6,301,891	.38422	2,421,284	.44562	2,808,261	16.0

G. Special Consideration

Several parties have requested that we recognize their status as exempt from the incremental pricing provisions of the NPGA and provide special treatment. This includes various customers claiming an agricultural exemption, schools (UC), Edison, and cogeneration. We are unable to provide any special treatment for these parties in this proceeding.

Our discretion in this regard is severely limited by the large amount of the undercollection and the relatively small number of nonexempt customers - representing only about 12 percent of the gas sales on Schedules G-2, 50, and 52. Based on the oil prices adopted in this proceeding any relief for these customers would have to be made up by the residential class, particularly lifeline. That result would be inconsistent with our guidelines.

With respect to cogeneration, this Commission has already provided for a cogeneration incentive gas rate, by D.91109, dated December 19, 1979. PG&E has responded by filing A.59459 to implement such a rate, and contentions in regard thereto should be raised in that proceeding.

Port Costa asks for a freeze in its gas rates for one year while it installs alternate fuel capability. It cites the case of the ammonia producers who were authorized special treatment. It characterizes itself as a large employer in its community whose survival is at stake. It also asks that it be given 60 days' notice of gas rate increases so that it may adjust its prices accordingly and pass along its costs to its customers.

We are not able to provide such relief in this proceeding. The rate treatment for the ammonia producers was based on substantial evidence of crucial public interest of a statewide, and even national nature. As a P-4 customer, Port Costa is required to have alternate fuel capability already installed. Thus its request for additional time to do so is anomalous. Further, the frequency and magnitude of cost increases do not provide us the luxury of allowing 60-day grace periods from the date of a decision to its effective date. The resulting undercollection would be too great a burden.

At the hearing, Mr. Fulton, president of Port Costa, indicated that it is a prospective cogenerator and that coal may be a suitable alternate fuel for such a use. He asked that PG&E be ordered to "proceed immediately with Port Costa Products Company in any way possible to develop cogeneration to the greatest extent feasible".

We have previously imposed a rate of return penalty on PG&E for its lack of effort in developing cogeneration. Port Costa appears to be an ideal candidate for a coal-fired cogeneration project on mutually beneficial terms. Thus, though we will not order PG&E to proceed as requested, we will examine its relationship with Port Costa as we review its cogeneration efforts in future proceedings.

UC has proposed a change in the wording of the "Applicability" paragraph of PG&E's Schedule G-52. The proposed change modifies the alternate fuel capability requirement in a fashion previously authorized by this Commission in D.91201 with respect to SoCal tariffs. There is no opposition to the change. It is reasonable and will be adopted.

H. "<u>Rate Design Mechanism</u>"

Staff witness Miller proposed that the Commission adopt a rate design mechanism with the intention that, with the adoption of certain parameters, the scope of rate design issues in offset proceedings could be narrowed and rates predicted.

Our adoption of rate design guidelines addresses much the same concerns as Mr. Miller and achieves a satisfactory result in this regard. We do find interesting Mr. Miller's discussion of "simultaneous" and "sequential" rate increases, and we suggest that rate design testimony in future proceedings might profitably address these concepts, as Mr. Miller's discussion provides a useful basis for understanding a rate design proposal where the adopted revenue requirement is more or less than the revenue requirement underlying the rate calculation.

VII. Other Issues

A. Zero Cost of Gas

Staff witness Fowler recommended that "the cost of gas available for sale and the related franchise fees and uncollectibles be removed from the general rate case test year revenue requirement and transferred to the GAC proceeding. The revenue requirement remaining for the test year would be known as "base revenue" and be synonymous with the SAM margin. This would simplify determination of GAC revenue. It has been authorized for CP National and is proposed in the pending SoCal general rate case proceeding.

Although the recommendation appears reasonable, we refrain from adopting it in this proceeding. We prefer to defer consideration until the SoCal general rate case decision so that the matter may be fully evaluated.

B. "Conservation" Issues

Robert Gnaizda appeared on behalf of several protestants representing low income and minority persons and argued that the rate increase would be unnecessary if PG&E had engaged in effective conservation efforts over the last decade. He offered several specific proposals for Commission consideration and stated his intention to subpoena PG&E officials to testify. The presiding Administrative Law Judge ruled that the specific areas were not relevant to a limited purpose gas offset proceeding. We affirm his ruling.

The particular matters raised by Mr. Gnaizda include the following: conservation and the poor, an energy ombudsperson, public members on the board of directors, employee discounts, and affirmative action. A brief comment is appropriate as to the basis for our ruling.

With regard to conservation and its impact on the poor, we have consistently resisted the introduction of a means test into the lifeline concept at the Commission level. Such a policy development should come from the Legislature. The subjects of an energy ombudsperson and public board members raise major jurisdictional issues and are appropriate in either a general rate case or at the Legislature. Employee discounts have been considered in previous general rate cases and can be again considered there in the future. Affirmative action is a matter pending before this Commission in C.10308, an investigation on the Commission's own motion. There is no basis for consideration of these issues in an offset proceeding.

Findings of Fact

1. In Application Nos. 59249 and 59406 PG&E seeks a combined total increase in gas department revenue of $945 million for the test year 1980. The request reflects principally the increase in purchased gas obtained from PG&E's principal suppliers, El Paso and PGT (Canada).

2. Interim Decision No. 91336, dated February 13, 1980, granted PG&E interim relief designed to produce an annual revenue increase of $304.9 million.

3. PG&E's policy of maximum placement of California gas and Canadian purchases at contract minimums is a reasonable basis for setting rates for the test year 1980.

4. PG&E's estimate of California deliveries is based on more current information and is reasonable.

5. Staff's estimate of El Paso deliveries best reflects current information and average year weather conditions.

6. Staff's estimate of withdrawals from Coalinga Nose is reasonable and reflects prudent policy judgments.

7. The use of the November 30, 1979, recorded balancing account balance subject to audit is reasonable to avoid unnecessary further undercollection.

8. Staff's proposed balancing account adjustment to reflect a credit to the SAM balance for revenues from sales to SoCal allocated by PG&E to carrying costs is reasonable and consistent with D.90424.

9. Staff's proposed balancing account adjustment relating to cost recovery of odorization facilities correctly deletes charges fixed in nature bearing no direct relationship to the cost of purchased gas.

10. PG&E's sales estimates to classes, with the further assumption that additional sales will be made on the G-55 schedule, provides a reasonable basis for setting rates.

11. Based on the foregoing, PG&E's additional revenue requirement is $418,534,000.

12. The specific prudency test proposed by TURN is unnecessarily rigid.

13. The rate design principles adopted in D.91107 are reasonable and should be applied herein, except as modified slightly.

14. Fully allocated average cost of service is not a meaningful measure in setting gas rates.

15. Rolling in incremental gas prices is not consistent with national energy policy.

16. Conservation potential within the lifeline sales is relatively slight.

17. Cogeneration is an important conservation measure that is effectively promoted by basing gas rates to industrial customers on alternate fuel prices.

18. The "average lifeline rate" is reasonably computed based on adopted residential customer charge revenues divided by adopted lifeline sales volumes plus the lifeline commodity charge.

19. The guideline relating to the Tier III residential rate should be modified as stated in the body of this decision.

20. Alternate fuel price information should be interpreted conservatively in times of high hydro availability.

21. The differential between G-50 and G-52 rates should be reduced to 3¢ per therm.

22. The guidelines applicable to G-55 and G-57 should be modified to base such rates on current market prices rather than contract prices. As such the rate should be uniform. The adopted rate provides an incentive for cogeneration.

23. The rate applicable to sales to SoCal should reflect gas supply policy considerations prevailing at the time the contract was made.

24. Staff's basis for calculation of the Palo Alto rate is reasonable.

25. Exempt classification created by the NGPA will not be recognized in this proceeding.

26. The cogeneration incentive gas rate should be examined in A.59459.

27. No rate freeze is warranted for Port Costa Products Company.

28. The applicability provision of PG&E's G-52 tariff schedule should be modified as proposed by US. (U.C)

29. The zero cost of gas concept should not be applied until after consideration in the pending SoCal proceeding.

30. Affirmative action, employee discounts, public members on utility boards of directors, energy ombudsperson, and consumption patterns by the poor are matters more properly resolved in some forum other than a gas offset proceeding.

31. Because there is substantial undercollection and a significant increase in costs, there is an immediate need for rate relief. Therefore, the effective date of this order shall be the date hereof.

32. The increase in rates and charges authorized by this order is justified and reasonable; the present rates and charges, insofar as they differ from those prescribed by this decision, are for the future unjust and unreasonable.

Conclusions of Law

1. PG&E should be authorized to increase its gas rates as set forth in Appendix A.

2. The rate design principles applied herein are appropriate.

3. The applicability portion of the G-52 tariff should be revised as set forth in Appendix B.

FINAL ORDER

IT IS ORDERED that on or after the effective date of this order Pacific Gas and Electric Company is authorized to file the revised tariff schedules attached to this order as Appendices A and B and cancel its presently effective schedules. The revised tariff schedules shall become effective five days after filing. The revised schedules shall apply only to service rendered on or after the effective date thereof.

The effective date of this order is the date hereof.

Dated APR 29 1980, at San Francisco, California.

President

Commissioners

Commissioner Vernon L. Sturgeon, being necessarily absent, did not participate in the disposition of this proceeding.

A.59249, 59406 ALJ/jn

Appendix A

Pacific Gas and Electric Company
Statement of Commodity Rates
(Cents per therm)

Type of Service*	Commodity Rate	GEDA	Effective Commodity Rate
Residential			
Tier I	28.908	.124	29.032
Tier II	56.581	.124	56.705
Tier III	66.574	.124	66.698
Nonresidential			
G-2	44.438	.124	44.562
G-50	45.750	.124	45.874
G-52	42.750	.124	42.874
G-55	40.242	.124	40.366
G-57	40.242	.124	40.366
G-60 LL	27.908	.124	28.032
G-60 NLL	~~42.495~~ 40.234	.124	~~42.619~~ 40.358
G-61, -62, -63 LL	30.402	.124	30.526
G-61, -62, -63 NLL	38.054	.124	38.178
SoCal Gas	43.087	-	43.087

&&&

* Schedule G1-N: First 300 therms at 56.705; Excess at 66.698.
Schedules GM/S/T-N: All use at 56.705.
Schedule G-30: Increase commensurately with Schedule G-2.

Appendix B

The "Applicability" statement of PG&E's Schedule No. G-52 shall be modified to provide as follows:

> "Applicable to natural gas service to uses classified in Rule 21 as P3 and P4, at facilities capable of burning as alternate fuel, on a regular basis, oil with a viscosity higher than 150 Saybolt Seconds Universal (SSU) at 100°F (commonly referred to as Grade No. 5 and Grade No. 6 fuel oil)."