ALJ/jt

Decision 84-12-066 December 28, 1984

ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of SOUTHERN CALIFORNIA GAS COMPANY and PACIFIC LIGHTING GAS SUPPLY COMPANY to revise their rates under the Consolidated Adjustment Mechanism (CAM) to offset changed gas costs resulting from changes in the price of natural gas purchased from EL PASO NATURAL GAS COMPANY, TRANSWESTERN PIPELINE COMPANY, PACIFIC INTERSTATE TRANSMISSION COMPANY, and California sources; to adjust revenues to recover the undercollection in the CAM balancing account; and to implement a new natural gas purchase sequencing policy.	Application 84-09-022 (Filed September 11, 1984)

(See Appendix A for appearances.)

I N D E X

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INTERIM OPINION

I. Introduction and Summary

On September 11, 1984, Southern California Gas Company and Pacific Lighting Gas Supply Company (SoCal) filed Application (A.) 84-09-022 with this Commission, pursuant to the Consolidated Adjustment Mechanism (CAM) procedures. The initial application proposed a CAM decrease of $86.5 million, which was updated to a $145.6 million decrease by further testimony filed on October 23. When the company's authorized $78.9 million general rate increase and $17.4 million liquified natural gas (LNG) amortization are considered, however, SoCal is actually seeking a net rate decrease of about $49.3 million.

A prehearing conference was conducted in San Francisco on October 5, followed by ten days of evidentiary hearings in Los Angeles (October 29 to November 2) and San Francisco (November 5 to 9). Oral argument was heard before the Commission en banc on the afternoon of November 14. Concurrent opening briefs were filed by November 21, to which SoCal replied on November 27.

This decision generally endorses the gas sequencing strategy advocated by the Commission Public Staff Division (staff) (PSD). We also authorize a total rate decrease of about $98 million. This decrease is spread to the residential, commercial, and industrial customer classes on an equal cents-per-therm basis with some reallocation of the decrease within the industrial class.

As with most CAM proceedings there is a natural division of major issues between (1) revenue requirement issues and (2) rate design issues. In this proceeding the most controversial revenue issue was gas sequencing. The secondary revenue issue was the choice of the length of time over which to amortize the balancing account.

Because this case was the culmination of several cases dealing with rate design, there was a panoply of rate issues. The most heavily contested was, of course, the spread of the revenue decrease. Of equal interest was the staff's new long-term rate design policy which was introduced for the purpose of seeking our preliminary endorsement.

So that we can illustrate our rate design discussion with real rather than hypothetical numbers, we will first arrive at the revenue requirement before dealing with the rate design.

II. Revenue Requirement

Cost of Gas

One of the first elements needed to calculate the revenue requirement is the cost of gas. In order to arrive at the forecast cost of gas, a decision on the gas sequencing policy or guidelines is necessary.

A. Sequencing

The first issue we will discuss in this decision is sequencing. The questions and issues we will be addressing are:

1. What is the sequencing issue?
2. Why is the issue so important at this time?
3. What is the significance of sequencing?
4. SoCal's suppliers and their prices.
5. Incremental versus average pricing.
6. Discretionary-nondiscretionary takes.
7. Adopted sequence strategy.

1. What Is The Sequencing Issue?

The sequencing issue at its most elemental level is "From whom does SoCal buy its gas supplies"? We have generally required the utilities to practice a least-cost purchasing strategy in order to assure the consumers the lowest prices available. This general policy was restrained by contractual obligations. We also realize that there can be other significant considerations in making these purchasing decisions. The staff, in this proceeding, identified some generally accepted goals of sequencing as follows:

1. Provide a least-cost gas mix to distribution utilities.
2. Promote competition among suppliers.
3. Provide long-term gas supplies.
4. Maintain a variety of gas suppliers.

Consider the following hypothetical example. Suppose that SoCal has a total demand of 135 units of gas that it could purchase from four different sources - A, B, C, and D as shown on the following table:

Supplier	Gas Available	Average Cost	Purchased
A	100	$3.00	
B	34	$3.00	
C	20	$6.00	
D	2	$4.00	
Total requirements	= 135		

The sequencing issue then is from which suppliers and in what quantities does SoCal purchase its gas supplies, while keeping our goals firmly in mind. It should be pointed out that this example is at a very elementary level and that we will be considering further complications as we continue our discussion.

2. Why is This Issue Timely?

It must be first pointed out that in moving gas from the ground to the consumer there are two very important interface points (1) producer-supplier and (2) supplier-distributor. In the past the prices at both of these two points involved very complicated contracts usually involving such things as minimum bills, take-or-pay, minimum takes, demand-commodity rates and cost of service. All of these complications in the middle of the distribution stream tended to mask the market signals between consumers and producers. The major effect is that there was and continues to be an excess supply of gas while at the same time prices continued to rise. To the extent that these contracts and rates have been regulated, they are within the jurisdiction of the Federal Energy Regulatory Commission (FERC).

For a number of years we have sought to have FERC alter these contracts in the public interest. In more recent times there came to be a national movement to have the producer-supplier and or supplier-distributor relationships rationalized. Recently, FERC has issued a series of orders (380 series) that essentially remove the competitive barriers from the supplier-distributor relationship, thus freeing the distributors to pursue a least-cost supply mix. This action also has the effect of placing the responsibility for exceptions to a least-cost mix with the regulators of the distributors, usually the state commissions. Therefore it is now within our purview to decide on the trade-offs among the conflicting goals mentioned earlier.

While the complex arrangements between the suppliers and distributors are basically gone, these same complex arrangements still exist between producers and suppliers. These complexities come back to haunt us when we try to weigh the advantages of average cost pricing versus incremental as proposed by staff or avoidable cost pricing as proposed by SoCal. Also FERC exempted from its new rules those projects involving the Alaskan pre-built projects. We will therefore face a very complex situation in comparing the prices of competitors involved with the "pre-built" project with those not so involved.

3. Significance of Sequencing

At this point, we will examine the significance of sequencing to SoCal. The sequencing strategy of SoCal is considered in its CAM proceedings because it is a gas purchasing issue. All such issues are subject to a reasonableness review, where we examine the past practices of the utility and then decide whether or not they were reasonable. If not, we make monetary adjustments. In order to minimize its exposure SoCal seeks sequencing guidelines from us before the fact. We chose not to issue any preliminary guideline given the complexity of the case and the range of positions of the parties.

A rough estimate of SoCal's risk exposure can be made at this point. In this proceeding there were four different purchasing strategies advocated by different parties all of which were supposed to fulfill our goals. The various sequence strategies produced average costs of gas for SoCal that ranged from 38.30 cents per therm (¢/th) to 38.53 ¢/th. The difference between the high and low (.23 ¢/th) multiplied by the total gas demand produces a dollar difference of $21,000,000 for a one-year period. This goes a long way in explaining SoCal's extreme desire for immediate guidelines from us. It is also clear that there are large dollar trade-offs in selecting how to weigh the various goals.

4. SoCal's Suppliers and Related Gas Prices

This section provides a brief description of each SoCal supplier and related prices.

a. <u>California Sources</u>

> SoCal buys gas directly from numerous California gas producers. This gas is produced in association with oil and SoCal currently takes all available (about 75 million cu. ft. per day (MMcf/d) or 3% of total SoCal gas supply). Prices are generally established by NGPA Section 105 (current average price 34.97¢/th).

b. Traditional California Federal Offshore

Small offshore gas producers not affiliated with SoCal/PLGS also produce gas associated with oil production. Total production of approximately 38 MMcf/d or 1.5% of SoCal's available gas supply is taken at prices regulated by NGPA Section 110 (current average price 33.09¢/th).

c. The Pacific Offshore Pipeline Company (POPCO)

POPCO, an affiliate of Pacific Lighting, is the only purchaser of 23 MMcf/d of "sour" gas produced in association with oil by Exxon at the Hondo platform in the Santa Barbara Channel. The gas cost alone (commodity cost) established by NGPA Section 109 currently at 27.01¢/th is the least expensive supply to SoCal. However, the fixed costs of the recently constructed gas processing plant and pipeline ensure a high annual fixed cost of service to POPCO (approximately $43 million in 1985) and add 40.00¢/th to the gas cost.

d. The Pacific Interstate Offshore Company (PIOC)

PIOC, another affiliate of Pacific Lighting, is the only purchaser of gas from the Pitas Point field (operated by Union and Texaco) in the Santa Barbara Channel. At 100 MMcf/d this one new source provides approximately 3.5% of available gas supply. A gas commodity cost of 35.00¢/th, ~~established by contract~~, is the highest single supplier cost to SoCal. The transportation cost of service to PIOC is 2.3¢/th, for a total unit cost of 37.3¢/th.

e. The Pacific Interstate Transmission Company (PITCO)

PITCO, another affiliate of Pacific Lighting, purchases gas from Canadian producers which is transported via various Canadian and U.S. pipelines utilizing the Alaskan pre-built project. The contract quantity at 216 MMcf/d is about 8% of available SoCal supply. SoCal/PLGS have recently renegotiated a contract with the Canadian producers (now approved by the NEB) for a minimum gas take of 130 MMcf/d, and a competitive gas commodity cost of 28.54¢/th. However, substantial fixed cost recovery ($166 million) of the recently constructed Alaskan pre-built facility results in a further 20¢/th transportation cost (at 100% gas take) for a total cost of 48.54¢/th.

f. Transwestern Pipeline Company

Transwestern is an established SoCal supplier buying gas in the southern half of the U.S. Transwestern gas supply available to SoCal is forecast at 670 MMcf/d (24% of SoCal's total supply availability). Its average commodity gas price is determined biannually before the FERC, and currently is at 34.4¢/th (includes some fixed cost recovery).

g. El Paso Pipeline Company

SoCal's largest and oldest supplier, El Paso, purchases gas throughout the southern half of the U.S. SoCal forecast supply availability from El Paso at 1,679 MMcf/d or 60% of SoCal's total supply availability. Its average commodity gas price is determined biannually before the FERC and is currently 34.52¢/th (includes some fixed cost recovery.

5. Incremental Versus Average Cost Pricing

Before we discuss the concepts of the particular pricing type that we will use, an example is helpful. The table on the following page contains the example that we used earlier, with the additional complications of having the average cost of gas broken down into a demand charge and a commodity charge. The object of this exercise is to choose the suppliers and quantities.

Supplier	Avail.	Avg. Cost	Demand Charge	Commodity Charge	Take
A	100	$3.00	$50.00	$2.50	
B	34	3.00	25.00	2.26	
C	20	9.75	75.00	6.00	
D	2	5.00	2.00	4.00	
			Total Requirements =		135

Scenario I

Least Cost - no other considerations

			Total	Avg.
A	100	(100x2.50)+50=	$300.00	
B	34	(34x2.26)+25=	102.00	
C	0		0	
D	1	(1x4.00)+2=	6.00	
		407/135=3.01	$408.00	3.02

Scenario II

50% nondiscretionary - remainder incremental sequencing

A	50	(50x2.50)+50=	$175.00	
B	17	(17x2.26)+25=	63.42	
C	10	(10x6.00)+75=	135.00	
D	1	(1x4.00)+2=	6.00	
	78		$379.42	
C	10	(10x2.25)	22.50	
B	17	(17x2.26)	38.42	
A	30	(30x2.50)	75.00	
	57		$135.92	
	57+78=135			
			$515.34	$3.82

Scenario III

50% nondiscretionary - remainder average cost sequencing

	78		$379.42	
A	50	(50x2.50=125)	125.00	
B	7	(7x2.26=15.82)	15.82	
	135	520.24/135=3.85	$520.24	$3.85
		OR		
B	17	(17x2.26=38.42)	$ 38.42	
A	40	(40x2.50=100)	100.00	
			$517.84	$3.84

Scenario I

This scenario shows the choice of suppliers simply based on the average cost of gas. Our example is easy in that no choice is required between Suppliers A and B. Also, the example is simplified in that we have calculated the average cost of gas for each supplier at its full availability, not over its sales.

Scenario II

This is the most meaningful example applicable to the problem of sequencing facing us. This example shows some of the types of choices that face us and their consequences. This example makes the following major assumptions:

1. None of the suppliers can survive unless the distributor buys at least 50% of its available supply.
2. Continued competition and long-term firm supplies require the existence of all four suppliers.

We can see that the order is to take 50% from each supplier as a first level of takes and then the second level is chosen on the basis of the incremental costs (cost of last unit taken). Thus, we see that the cost of our assumptions is about $107 (515.34-408=107).

Scenario III

This example is intended to show the difference between sequencing the discretionary takes of gas on an average cost basis (total cost ÷ total takes) rather than the incremental basis. This example has two prices because Supplier A and Supplier B both have the same average cost ($3.00).

More importantly, the example shows that the issue of incremental versus averaging cost strategy is raised only when some policy assumptions or other constraints are present. Some of the issues raised in the example are listed below:

1. What are the policy goals warranting a deviation from average cost pricing?

2. How can those goals be implemented?

3. What is the effect of the deviation - both long and short term.

4. How do you calculate the incremental and the average costs?

6. Discretionary-Nondiscretionary Takes

As can be seen from the entire previous discussion, the sequencing issue is only raised when there is an oversupply of gas. In this situation the question can be viewed in terms of what gas is turned back as well as what gas should be purchased. Unfortunately, the parties have failed to consider in their so-called long-term scenarios any possibility of a gas shortage situation. We find, however, that our test for a new long-term supply source is helpful for sequencing as well as for rate design purposes. In Decision (D.) 82-04-116, we found that the appropriate test by which to consider a new gas project was by comparing the full cost of the new supply source with the price of crude oil delivered to refiners over the life of the gas supply project. If the parties had considered such a test for the existing supplies it might have been helpful in deciding what current sources to protect and why. Without this analysis, the first step of our sequencing analysis is to consider if there are any nondiscretionary supply takes among all of the current suppliers.

All parties agree that there are such nondiscretionary supplies. The staff argues that 100% of the California on-shore and 60% of the PITCO (Canadian) supplies are contractually required. The next block of gas that the staff considers nondiscretionary is the so-called minimum operational requirements (MOR). This is defined as associated gas. This is gas produced as a by-product of oil production. The choice facing producers of this gas is that it will either be taken or wasted. It is generally recognized that the former choice is preferable. The calculation of the percentage of associated gas on the systems of the large suppliers is very difficult. However, the staff has made a reasonable estimate which is that 20% of El Paso's, 37% of Transwestern's, and 50% of POPCO's supplies constitute those systems' MOR as defined by staff.

SoCal arrives at a different level of takes as minimum. SoCal's proposition is that it should take on a ratable basis from all suppliers 40% of each supplier's contract quantity. SoCal argues that this quantity contains the MOR as defined by staff and, in addition, is a sufficient quantity to assure the long-term viability of all of the existing suppliers. SoCal failed to show any basis for this 40% amount other than it produced a total volume of gas equaling its total P-1 and P-2a demand.

Finally, El Paso proposes that the minimum takes from each supplier be set at 60% of contract quantity for the same general reasons that SoCal picked 40%. Both SoCal and the staff agree that the 60% level is much too high to encourage competition among gas suppliers.

We will adopt the staff's level of minimum nondiscretionary takes because it is the only proposal based on specific quantifiable criteria. As a practical matter, at this level of takes the choice seems to have no major effect on any supplier with the exception of PIOC (Pitas Point) gas, which is not taken under the staff's proposal but would be taken at least up to 40% or 60% under SoCal's or El Paso's proposals. However, no sufficient showing was made as to the necessity or desirability of protecting this gas at its present prices.

Discretionary Gas Sequencing

At this point in our discussion we have determined that there is a certain level of nondiscretionary takes; the next problem is to decide on how to sequence the gas from the nondiscretionary level to the total amount required. Sequencing proposals were advanced by SoCal, El Paso, and staff. There were four proposals put forward for our consideration and they can be divided into two groups as follows:

1. Average cost pricing
   a. El Paso - average with certain stated exceptions.
   b. Staff - pure average cost sequencing.
2. Incremental cost pricing
   a. SoCal's avoidable cost pricing.
   b. Staff's incremental cost pricing.

We will first decide on whether incremental or average cost pricing is the more desirable in this case; then we will proceed to which type of either choice is the more appropriate. The following table compares the calculation of the sequencing price under three of the above methods:

Table 1

SEQUENCING PRICES UNDER
ALTERNATE PROPOSALS

Source of Natural Gas	Sequencing Price Under PSD Incremental Cost	SoCal Avoided Cost	PSD Average Cost
California Source	34.97	34.97	34.97
Old Federal Offshore	33.09	33.09	33.09
El Paso			
(A) Below Producer Take-or-Pay Level	30.73	25.41	36.25
(B) Below Minimum Bill Level But Above (A)	30.73	29.50	36.25
(C) Up to Canadian Take Level But Above (B)	34.52	33.29	36.25
(D) Above Canadian Take But Above (C)	36.24	34.99	37.53
Transwestern			
(A) Below Producer Take-or-Pay Level	30.92	26.56	36.46
(B) Below Minimum Bill Level But Above (A)	30.92	31.10	36.46
(C) Above Minimum Bill Level	34.49	37.07	36.46
PITCO	28.60	28.60	47.30
POPCO	21.09	21.09	64.57
PIOC			
(A) Below Producer Take or Pay	36.60	30.56	37.45
(B) Above Producer Take or Pay	36.60	35.95	37.45

Average Cost Sequencing

Average cost sequencing would sequence discretionary gas takes by SoCal based on their total unit cost to SoCal. This approach can simultaneously reduce the rate structure manipulation potentially inherent in avoided cost, work toward optimizing long-term purchases since all costs of delivered gas are included, and provide a competitive pressure for pipelines to streamline their operations benefiting gas consumers over the long term.

However beneficial average cost sequencing is over the long term, there are a number of drawbacks to this approach that the PSD has identified. These include calculation difficulties, loss of short-term optimization, and impact on new sources of gas.

We have previously shown in our example that once it is decided that there is some level of nondiscretionary takes, then incremental price sequencing for the remaining portion produces the least-cost method of sequencing. In this proceeding the dollar difference between average cost sequencing and incremental sequencing has been estimated to range from $11 million to $102 million primarily depending on how the Canadians react to our decision.

Another drawback to average cost pricing is its effect on SoCal's newer suppliers. SoCal's suppliers can be generally divided into three groups: (1) the suppliers (El Paso and Transwestern) having the largest, oldest, most depreciated systems and hence low transportation costs--these suppliers serve the bulk of the SoCal market; (2) the traditional California suppliers, both onshore and offshore, serving a small part of the SoCal market largely from associated gas and without any SoCal investment in gas gathering systems; and (3) the new suppliers--PITCO, POPCO, and PIOC that have recently built or are paying for new transportation and ancillary facilities based on gas suppliers from Canada and offshore California. It is the latter group of suppliers who have high transportation costs for the next several years as debt holders are repaid their investment. It is these suppliers, as a group, who are most negatively affected by any average cost sequencing formula.

Incremental Cost Sequencing

Both the staff and SoCal favor an incremental approach because it produces the greater short-term cost benefit, but more importantly its indirect effects are to protect the sources of supply with high fixed cost and will thus insure several long-term suppliers. We recognize, along with the staff and SoCal, the importance of maintaining the diversity of SoCal's sources of supply. We are persuaded that the significant differences which currently exist in the "vintages" of SoCal's suppliers dictate that at this time discretionary takes should be sequenced on an incremental basis. We are also mindful that adoption of average cost sequencing for SoCal at this juncture risks the loss of a substantial portion of the benefits which SoCal has recently obtained from its Canadian suppliers. Therefore, we will adopt at this time an incremental sequencing method for SoCal's discretionary takes.

However, we are also convinced that over the longer term we would prefer to move SoCal's sequencing policy toward an average cost basis; consistent with the policy which we adopt today in our decision in Pacific Gas and Electric Company's (PG&E) Gas Adjustment Clause proceeding. Average cost sequencing has the important long-term advantage of placing all supplier cost elements under the scrutiny of the marketplace. Today we will take a first step in that direction, by adopting TURN's suggestion that average costs be used as a "tiebreaker" when the incremental costs of two competing suppliers are within a small price "window" of each other. This procedure will be discussed in greater detail below.

Avoidable Versus Incremental

With our decision to use the incremental method, we can now decide whether to use the staff's incremental approach or SoCal's avoidable approach. Both methods have the same theoretical basis which is to recognize the cost of the next unit purchased. The methods differ in the calculation of the "incremental" price.

There is a timing aspect difference between the two methods. The staff's method offers a more immediate approach, whereas the company's is more forward looking by recognizing to a greater degree the "opportunity costs" in computing the incremental price. There are also some inconsistencies in both approaches that we will point out as we continue our discussion. We will strive to avoid as many inconsistencies as possible.

The chart presented earlier discloses that the controverted issues surround the following:

1. Treatment of FERC Account 191 over/undercollections.
2. Potential take-or-pay carrying costs.

It seems that the parties contest these issues based on some judgment of to what degree these costs are indeed unavoidable. The first issue that we will consider is the "take-or-pay" carrying costs.

A decision to purchase a particular increment of gas from one supplier over another can cause the supplier whose gas is not purchased to incur take-or-pay obligations to its producers. When an FERC regulated pipeline company incurs take-or-pay prepayments due to reduced demand, the cost of these prepayments is reflected as fixed charges in future commodity rates. FERC Order No. 380 specifically recognized the right of a pipeline to include reasonable take-or-pay costs in rates.

SoCal argues that some consideration for this future obligation should be reflected in determining the avoidable cost. In some cases, volumes of gas not taken by Pacific Lighting Utilities may be carried by their suppliers for several years, resulting in ever increasing obligations. SoCal's proposal does not assure any supplier of take-or-pay coverage. However, it does attempt to factor into avoidable cost sequencing these potential costs.

The staff proposes that incremental cost not include the new take-or-pay criterion proposed by SoCal. The PSD notes that potential take-or-pay prepayments to producers are an ongoing matter of negotiation between suppliers and their producers, i.e., El Paso has proposed a special marketing program that involves release of gas for direct sales in exchange for reductions in contractual take levels. Also, staff notes that El Paso has demonstrated its intention to negotiate with its gas producers on take-or-pay in many forums and more directly by carrying a balance of only $6 million in FERC Account 165 which is the take-or-pay prepayment account.

The PSD supports these attempts to decrease take-or-pay agreements between El Paso and its gas producers since this, in turn, could reduce minimum bill volumes between SoCal and its suppliers and mean greater flexibility to purchase in a least-cost manner by both SoCal and its suppliers. The staff believes that it would be counterproductive to basically recognize take-or-pay prepayments in advance and reduce the pressure on suppliers to maintain their attempts to reduce take-or-pay exposure. Similar arguments can be made for Transwestern which, because of the operation of its 91% minimum bill, has less than $1 million in its FERC Account 165. Transwestern, like El Paso, can avoid large prepayments by successfully competing for the gas market in California while renegotiating take-or-pay levels with producers.

Hence, the PSD recommends on the basis of sending suppliers/producers a policy signal for greater industry flexibility, that potential take-or-pay obligation not be included as an avoided cost criterion. Of course, if and when take-or-pay payments are passed on as a result of FERC rate cases, then the payment becomes part of the fixed cost recovery in the minimum bill and would under incremental sequencing be deducted in cost of gas comparisons. However, any anticipated carrying charges resulting from renegotiated contracts should be excluded in the staff's view.

The next issue concerns the FERC "Account 191" surcharge. A brief review of the mechanics of Account 191 is in order. Account 191 is somewhat analogous to the SoCal CAM balancing account. FERC allows suppliers to adjust their commodity rates in semiannual Purchased Gas Adjustment (PGA) proceedings consistent with the gas cost estimating procedures adopted by the FERC. Any error in this estimation of gas costs--either an undercollection or an overcollection of revenues relative to actual costs--is remedied through the Account 191 surcharge in the following semiannual period. Other factors, for example, undercollections of liquids revenues relative to the revenue level incorporated in El Paso's cost of service per its last general rate case, RP82-33, and certain refunds are also put into the Account 191. The balance in the account at the end of the PGA period is then "spread" over the estimated sales level for the new PGA period. Due to regulatory effects, there is a three-month delay between the period during which the Account 191 balance is built up and the period during which the surcharge rate for that balance is applied. Furthermore, if a previous period's sales forecast fails to materialize, then the previous PGA period's Account 191 balance will remain undercollected. This undercollection will be included as a portion of the Account 191 balance to be applied as a surcharge to the next PGA period's rates.

SoCal argues that this liability for Account 191 undercollections is an unavoidable sunk cost that will be recovered in future PGAs. California receives about 75% of El Paso's total sales and therefore incurs 75% of the Account 191 surcharge in future periods.

Staff argues that there exists a potential for Account 191 manipulation to secure sequencing advantage. The staff therefore recommends that the price of incremental gas not be adjusted to reflect Account 191 over- or undercollections. The staff does recommend, however, that if Account 191 is seen as a fixed charge then 100% of the amount be deducted because it is a surcharge spread over all sales.

7. Adopted Sequencing Strategy

Discussion

We generally concur with the point of view reflected in the staff's recommendations which we interpret to be that the price used for incremental gas cost comparisons should reflect the immediate price. This is based on the concept that we want the market to know and reflect the consequences of the current prices. This leads us to reject adjustments of the price based on future consequences.

We believe that future consequences are not "fixed" and remain in control of both producers and suppliers. Based on this reasoning, we will adopt the staff's recommendation that the "take-or-pay" considerations not be included in the calculation of the incremental prices.

We are persuaded as well that the staff's recommendation to include 100% of any Account 191 balances in the calculation of incremental prices should be adopted. Inasmuch as it is the intention of the Commission to foster price competition between gas suppliers to California, it is in the best interests of all concerned to reduce any incentive in our sequencing formula which would permit manipulation of regulatory processes to gain an advantage in that competition.

Similar issue concerns the calculation of the price for the final segment of El Paso gas to be purchased to meet SoCal's forecast requirements of 2,588 MMcf/d. The staff, as well as the applicants, adds 1.7¢/th to the last segment of El Paso gas in calculating the incremental cost of that segment. This segment displaces Pan-Alberta volumes which are less costly than El Paso gas. If the Pan-Alberta volumes are not routed through El Paso's transmission system but rather through PG&E's Line 300, an additional cost of 1.7¢/th is incurred on those volumes. Therefore, in order to make a true economic comparison, this 1.7¢/th additional cost is added to El Paso's final segment of discretionary supply. SoCal and staff feel that this must be done because the last increment of supplies taken through the El Paso system, due to having the highest avoidable costs, is the one that incurs the 1.7¢/th additional cost.

El Paso argues that the 1.7¢/th should be added to the Pan-Alberta gas. However, El Paso ignores the fact that for the last increment of El Paso gas taken it is more expensive El Paso gas which displaces the less costly Pan-Alberta gas in El Paso's system. The only accurate way to assess the cost of taking El Paso's last increment is to recognize that by so doing, the El Paso gas causes the cost of the Pan-Alberta gas to increase by 1.7¢/th since the Pan-Alberta gas must be moved over to the El Paso/PG&E system to make room for additional El Paso gas through the El Paso system.

While the staff and SoCal may be correct in calculating the opportunity cost of the last segment of El Paso gas, this is not the proper consideration. We are concerned with the incremental price. The 1.7¢ properly should be assessed as it is incurred, that is, on the price of the Pan-Alberta gas (PITCO). We note that this does not affect the sequencing of Pan-Alberta gas, but could affect the takes of El Paso versus Pitas Point gas if demand grows beyond present forecasts.

Price Window

This last issue concerns the sequencing of gas when the incremental prices of more than one supplier are fairly close. Both the staff and SoCal advocate that there should be a price window. The general concept is that when two or more suppliers' prices are within a certain distance from one another then those sources would be taken on a ratable basis.

SoCal proposes that the window equal 1.5¢/th. This represents about a 5% margin for error in forecasting decisions which SoCal believes is reasonable. The staff, on the other hand, believes that this window is too large and provides too large a "comfort zone" for suppliers. The staff feels that there is little incentive for competition within the window. The staff therefore recommends that the window be .5¢/th. El Paso agrees with SoCal's proposal.

We agree that a window is reasonable in concept. Without a window a minute difference in price could have a major effect on the amounts taken from a particular supplier. We find merit in the arguments of SoCal that the staff's window is too small given the uncertainties in gas calculations, and the arguments of staff that SoCal's window is so large that competition could be discouraged. Thus we will adopt a window of 1.0¢/th.

Toward Utility Rate Normalization (TURN) proposes that within the window average cost prices be used as a tiebreaker. In other words, the supplier within the window with the lowest average cost would be sequenced first. Only if the average costs of the suppliers within the window are also within the window's size of each other does TURN recommend that pro rata takes be used.

We agree with TURN that some other method of sequencing within the window other than "ratable takes" is desirable. From our point of view, the producers will have carried the suppliers into the window and that further competition between sources of supply should be between the pipelines. TURN's refinement presents to the pipelines the prospect of occasionally having to compete on an average cost basis at a crucial point in the sequencing order. This possibility would provide an incentive for fixed cost control that is lacking in the incremental cost approach. We will adopt TURN's proposal for sequencing within the window.

The following table illustrates the sequencing guidelines proposed by SoCal, El Paso, and staff, whose guidelines we have adopted:

Table 2
Comparison of Supplier Gas Takes
Under Various Sequencing Methodologies
With Adopted Sales Forecast

Supplier Totals (Mth)	SoCal	Staff	El Paso	Adopted
California	286,690	286,690	286,690	286,690
Traditional Federal Offshore	166,690	166,690	166,690	166,690
Hondo	96,550	96,550	58,765	96,550
Pacific Interstate--SW	670	670	670	670
Pacific Interstate-Pan Alberta	833,980	833,980	500,390	833,980
El Paso	5,602,070	5,609,326	5,860,885	5,609,326
Transwestern	2,323,190	2,544,827	2,383,815	2,544,827
Pitas Point	228,893	0	280,828	0
Total Purchases	9,538,733	9,538,733	9,538,733	9,538,733
Weighted Average Cost of gas (¢/th)	38.40	38.35	38.60	38.35

Table 3
Weighted Average Unit Cost of
System Gas Supply
11/84 - 10/85
Under Adopted Sequencing

	MMcf	M-therms	¢/therm	M$
Basic Purchases				
California	26,713	286,690	34.97	100,255
Traditional Federal Off.	15,198	166,690	33.04	55,074
Hondo	4,197	48,275	64.57	31,171
Pac-Interstate--SW	61	670	31.94	214
Pac-Interstate-Pan Alberta 1/	47,046	500,390	47.80	239,186
El Paso 2/	125,560	1,309,590	36.25	474,726
Transwestern 2/	101,470	1,082,684	36.46	394,747
Subtotal	320,245	3,394,989		1,295,373
Discretionary Purchases				
Hondo	4,197	48,275	64.57	31,171
Pac-Interstate-Pan Alberta	31,370	333,590	47.80	159,456
El Paso 2/	353,320	3,685,127	36.25	1,335,859
Transwestern 2/	104,025	1,109,946	36.46	404,686
Transwestern 2/	16,790	179,149	34.49	61,788
El Paso 2/	75,313	787,657	34.52	271,899
Subtotal Basic and Discretionary Purchases	905,260	9,538,733	37.32	3,560,232
Storage Withdrawal	92,021	989,890	36.49	361,211
Storage Injection	-84,437	-901,700	36.05	-325,062
Company Use	-7,516	-79,130		
Unaccounted for	-13,867	-151,907		
Carrying Costs Pre-Payments on Canadian Gas 3/				4,556
Minimum Bill to PICO 3/				2,048
TOTAL GAS SOLD	891,461	9,395,886	38.35	3,602,985

1/ Cost is based on 100% take of Pan Alberta gas.

2/ Cost is based on spreading El Paso and Transwestern demand charges over 75% of contract quantities.

3/ These costs are unavoidable.

B. Estimated Cost of Gas

With our sequencing discussion complete we can now continue to develop the revenue requirement. The next element is the cost of gas which flows directly from our discussion on sequencing and the sales estimate. Staff and SoCal agree on the sales estimate and it will be adopted.

C. CAM Balance

The next item requiring discussion is the CAM balance amortization period. The record in this case shows that the CAM balancing account is projected to be undercollected by $94.2 million at the end of December 1984. SoCal requests that this balance be amortized over a six-month period which results in a revenue requirement of $180.8 million at this time.

Staff, TURN, and CMA all recommend that we adopt a 12-month amortization period which results in a decrease in revenue requirement of about $86.6 million. Their reasoning follows these lines. First, there has been a substantial decrease in the cost of gas. Second, failure to pass through some of this reduction to the end use market will not indicate to the producers that if they reduce their prices there is the opportunity to sell more gas. Third, there has been substantial publicity concerning the reduced cost of gas; there will be a very poor public reaction if there is not some reduction in gas prices to all customers.

SoCal puts forth the usual arguments that a 12-month amortization period will lead to ever increasing balances with the attendant carrying costs.

SoCal fails to completely understand our intentions regarding balancing accounts. Although, it has been and continues to be our policy to try to achieve as low a balance as possible, the reason for this policy has been to provide for stable rates. SoCal is correct in acknowledging that large balances eventually result in large rate changes. However, an additional concept that has been accentuated in this proceeding is the need to reflect the true current cost of gas in the market. Short amortization periods of either over- or undercollections tend to hide the true present cost of gas. Finally, we concur that some incentive must be given to the gas producers.

A synthesis of these objectives leads us to conclude that as large a decrease as possible is desirable so long as there will be little if any rate increase in the spring CAM. This conclusion results in the choice of an amortization period somewhere between 6 and 12 months. We will adopt a 9-month period which results in a revenue requirement for this item of about $125.6 million. The wholesale balancing accounts will be amortized over the same period for the sake of consistency.

D. Revenue Requirement

Now that the major controversies regarding the revenue requirement have been decided, we can proceed to develop the final numbers. The cost of gas of $3,602,984,000 was developed in a previous section as a reasonable estimate for the cost of gas. Likewise, the amortization of the balancing account produced $120,497,000. The remaining elements are without controversy and will be adopted. The total revenue requirement decrease adopted is ($97,849,000). This revenue reduction will be spread over the rate schedules in our discussion of rate design issues. The revenue requirement is illustrated in the following tables which shows the effect of the three different potential amortization periods (6, 9, and 12 months).

Table 4

SOUTHERN CALIFORNIA GAS COMPANY

12 MONTHS BEGINNING NOV 1, 1984

CAM REVENUE REQUIREMENT

6-MO AMORTIZATION

Line No.	Item	M$
1	Cost of Gas Purchased	3602984
2	Carrying Cost of Storage Inventory	-1745
3	CAM Balance (Annualized)	180830
4	Subtotal (L1+L2+L3)	3782069
5	Adj for Fran & Uncol Acct Exp @ 1.915 %	72426
6	Gas Margin	1157918
7	NH3 Prod Surcharge (From Other Utilities)	-4821
8	Conservation Cost Adjustment (CCA)	92414
9	GEDA @ .00219 $/therm	20961
10	Subtotal (Sum L4 to L9)	5120967
11	Less Exchange Revenue	-10870
12	CAM Revenue Requirement	5110097
13	Revenue at Present Rates	5146458
14	Additional Revenue Required	-36361

Average Cost of Gas Sold: .40824

Wholesale Rates ($/tn)

G-60, Long Beach		
	Gross Rate	.39055
	Bal Acct Adj	-.00910
	Tariff Rate	.38145
G-61, SDG&E		
	Gross Rate	.38963
	Bal Acct Adj	-.01225
	Tariff Rate	.37738

12-03-84

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Table 5

SOUTHERN CALIFORNIA GAS COMPANY

12 MONTHS BEGINNING NOV 1, 1984

CAM REVENUE REQUIREMENT

9-MO AMORTIZATION

Line No.	Item	M$
1	Cost of Gas Purchased	3602984
2	Carrying Cost of Storage Inventory	-1745
3	CAM Balance (Annualized)	120497
4	Subtotal (L1+L2+L3)	3721735
5	Adj for Fran & Uncol Acct Exp @ 1.915 %	71271
6	Gas Margin	1157918
7	NH3 Prod Surcharge (From Other Utilities)	-4831
8	Conservation Cost Adjustment (CCA)	92414
9	GEDA @ .00219 $/therm	20961
10	Subtotal (Sum L4 to L9)	5059479
11	Less Exchange Revenue	-10870
12	CAM Revenue Requirement	5048609
13	Revenue at Present Rates	5146458
14	Additional Revenue Required	-97849

Average Cost of Gas Sold: $.40172

Wholesale Rates ($/th)

G-60, Long Beach	
Gross Rate	.39055
Bal Acct Adj	-.00631
Tariff Rate	.38424
G-61, SDG&E	
Gross Rate	.38963
Bal Acct Adj	-.00883
Tariff Rate	.38080

12-05-84

TABLE NO. 6

SOUTHERN CALIFORNIA GAS COMPANY

12 MONTHS BEGINNING NOV 1, 1984

CAM REVENUE REQUIREMENT

Line No.	Item	M$
1	Cost of Gas Purchased	3602984
2	Carrying Cost of Storage Inventory	-1745
3	CAM Balance (Annualized)	120497
4	Subtotal (L1+L2+L3)	3721736
5	Adj for Fran & Uncol Acc Exp @ 1.915%	71271
6	Gas Margin 1/	1141670
7	NH3 Prod Surcharge (From Other Utilities)	-4821
8	Conservation Cost Adjustment (CCA)	92414
9	GEDA (@ $.00219/therm)	20961
10	Subtotal (Sum L4 to L9)	5043231
11	Less Exchange Revenue	-10670
12	CAM Revenue Requirement	5032561
13	Revenue at Present Rates	5146458
14	Additional Revenue Required	-114097

Average Cost of Gas Sold .40572 $/th

Ammonia Producer Rate .365 $/th

Resale Rates ($/th)

G-60 (Long Beach)

Gross Rate .39055

Bal Act Adj -.00632

Tariff Rate .38423

G-61 (SDG&E)

Gross Rate .38963

Bal Act Adj -.00896

Tariff Rate .38067

1/ Includes 1985 adjustment of -$7,650,000.

III. Rate Design

This decision is the major rate decision for SoCal for the entire year. In the three proceedings (spring CAM, fall CAM, and general rate case), issues were raised concerning virtually every SoCal rate schedule. In addition to the specific rate issues, the staff proposed a major new long-term rate design policy in the fall CAM. The staff's long-term policy was not complete and was presented to elicit comments both from us and from other parties in the spring 1985 CAM proceeding. We will discuss the long-term policy first.

A. Long-Term Gas Rate Design Policy

In this proceeding the staff is proposing a change in long-term gas rate design policy. It proposes that the Commission approve its recommendation in concept now, then implement it in detail in the rates in the spring CAM for SoCal and the spring GAC for PG&E. The essence of the staff proposal is to shift from the current rate design, which is based on alternative fuel costs, to one based on the cost of gas.

Staff offers its proposal as a response to the continuing difficulties in managing the current rate design in the face of several significant changes in the gas industry. First, the decline in oil prices to levels below those of still-regulated gas prices has forced the Commission to consider numerous requests for special rates indexed to alternative fuel prices, in order to keep low priority industrial customers on the gas system. Administration of the special "targeted" rates that the Commission has approved is difficult and complex especially since the Commission has limited knowledge or control over the rapid fluctuations in the alternative fuel markets. Second, substantial new opportunities now exist for gas-to-gas competition among California's gas suppliers. A recent series of orders by the FERC has removed contractual constraints on competition among the pipelines supplying California. The deliverability of gas continues to exceed the demand, and the wellhead prices of several categories of gas will be deregulated on January 1, 1985. In this environment the staff argues that existing rate design policies, which tie industrial rates to artificial alternative fuel prices, are not structured to take advantage of the rapidly increasing competition among gas pipelines and producers. A new rate design policy in which rates for all customers move with the cost of gas will, the staff asserts, harness the new competitive forces in the gas market to yield lower rates for all gas consumers. In this way, the staff seeks to avoid a situation in which the benefits of competition accrue just to those customers with alternative fuel capability who can command lower rates with the threat of fuel switching. While the mechanics of the staff's proposal would be determined in the spring GAC and CAM proceedings, in concept the proposal would work as follows:

> Gas is purchased on a least-cost basis first with the incremental source of gas being the most expensive source supplied to the system to serve existing demand. Customers are matched with gas supply such that the highest priority customers have included in their rates the least-cost source of gas, and the incremental load is served by the more expensive incremental gas. As blocks of gas are matched up with blocks of demand, there is an allocation of pipeline and distribution fixed costs to derive the completed rate. (Staff Opening Brief, PG&E GAC A.84-08-67, p.29)

This allocation of fixed costs would reflect a division of the market between core and noncore customers. The core market is defined as customers in Priorities P-1 through P-2a; the noncore market consists of customers with fuel switching capability. The staff and the parties who commented on the staff proposal are in general agreement that making this allocation of fixed costs presents the Commission with a difficult task, one that holds the greatest risk of advantaging or prejudicing any particular customer class.

The absolute cornerstone of the staff's propsal is the rates to the noncore market will not change unless the cost of gas changes. This will eliminate the current practice of targeting industrial rates to the cost of alternative fuels, then setting high priority rates residually. The staff asserts that strict Commission adherence to such a policy would clearly signal gas producers that increased sales to the California industrial market will result only if the producers reduce wellhead prices to competitive levels.

TURN and SoCal oppose adoption at ths time of the staff proposal, stating that it lacks sufficient detail to permit any comprehensive response. TURN states that it will vigorously oppose any attempt to return to an allocated cost of service concept. While accepting staff's analysis of the need for a rate design policy that allows reflection of changes in the cost of gas in industrial customers' rates, TURN suggests an equal percentage or equal cents per therm rate policy will adequately achieve that goal for the near term. TURN also expresses concern that an expedited offset proceeding such as the spring CAM may not be an appropriate forum for considering such a major change in rate design policy. TURN suggests that this change be considered in SoCal's next general rate case. SoCal commends the staff's efforts in developing its proposal, but asks the Commission to reserve its approval until the means and results of implementing the policy have been discussed and fully understood.

We welcome the public staff's long-run rate design proposal as a thoughtful and timely response to the dramatic changes that are occurring in the natural gas industry. We share our staff's desire to move away from the complexities of targeted industrial rates linked to alternative fuel prices. We also recognize the importance of sending gas producers a strong signal back from the burnertip, to the effect that gas sales will increase only if producers reduce or maintain the cost of gas at competitive levels. Finally we are attracted to the idea of linking <u>all</u> rates, across the board, to the cost of gas, in order to provide all gas consumers with the potential benefits of expanded competition among gas pipelines and producers. We note that we are taking a significant step in that direction today, in both this case and the PG&E GAC, by allocating the significant rate reductions to all customer classes on an equal cents per therm basis, as proposed by TURN.

However, we will not approve the staff's proposal at this time. Although the concept is appealing, we do not want to commit ourselves to the path proposed by staff without some assurance that a fair and reasonable allocation of supplier and distributor fixed costs, a crucial element in the stff proposal, can actually be achieved. We share the concerns of PG&E and TURN that the details of this allocation should be studied before the concept is approved.

More importantly, the expedited time frame of this proceeding did not allow consideration of the staff proposal alongside other options for responding to the fundamental changes in the gas industry. We have been conducting an investigation into allowing carriage of customer-owned gas within California (OII-84-04-079). A number of parties to that proceeding urge us to allow intrastate gas carriage, both as an alternative to targeted rates for keeping low priority customers on the gas system, and as a way to promote competition at the wellhead. Our staff, which originally supported carriage, now prefers its long range rate design proposal, and urges us to delay approving carriage until the impact of the proposed long-term rate design is felt and gas producers begin to reduce prices for all customers (Staff Brief, PG&E GAC A.84-08-067, pp. 38-39). Until then, staff fears that carriage would segment the market, and allow carriage users to siphon off low cost gas, thus raising the average cost of gas to the distributor's captive core customers. Because carriage is a distinct alternative to the staff's rate design proposal, we prefer to give all interested parties, especially those in OII-84-04-079, an opportunity to address the common issues raised by both alternatives, or to propose further options. For this reason we direct staff to formulate expeditiously a proposal for how we may consider these issues.

B. Short-Term Rate Design

As was mentioned earlier some element of virtually every rate schedule was contested. Before embarking upon the task of distributing the $114 million reduction, we will first work from some general principles down to the specific rate schedules.

1. Residential Rate Structure

The issues contained in this area relate to the following:

1. Baseline Quantities
2. Number of Tiers
3. Residential Customer Charge

Baseline

The Baseline Act amends Public Utilities Code § 739 and requires the Commission to establish a baseline quantity of gas which is necessary to supply a significant portion of the reasonable energy needs of the average residential customer. Applicants' recommendations regarding changes in lifeline allowances necessary to comply with the Baseline Act were presented in the 1985 general rate case (A.84-02-25).

Subsequent to completion of hearings in that proceeding, the Assembly passed Resolution No. 58 to more clearly state its intent toward the baseline program. Baseline allowances, as now defined in the resolution, are to be from 50 to 60% of average residential consumption during spring, summer, and fall and from 60 to 70% during winter. Any increase in cost resulting from the change from lifeline to baseline is not to exceed 5%. The baseline allowances proposed by applicants in A.84-02-25 meet all of the resolution standards except for the 5% limit, which is exceeded in climate zones 2 and 3 in winter months. To correct this problem applicants recommend that the baseline quantity for zones 2 and 3 be set at the same proportional change in baseline quantity recommended for zone 1. Both staff and SoCal recommended in A.84-02-25 that a revision from 81 therms to 72 therms for zone 1 was necessary during winter months to comply with the Baseline Act. This is a reduction of 11% in monthly winter allowance. Applying this reduction to zones 2 and 3 would produce the winter allowances shown in the following table:

Table 7

THERMS

Present Lifeline			Baseline Proposed in A.84-02-25			Adjusted With 11% Reduction From Present Lifeline		
Zone 1	Zone 2	Zone 3	Zone 1	Zone 2	Zone 3	Zone 1	Zone 2	Zone 3
81	106	141	72	75	103	72	94	125

With this adjustment, the quantities proposed by SoCal are reasonable and will be adopted.

Climate Zone	Present Lifeline	Adopted Proposed Baseline SoCal	Proposed Baseline Staff 55%
55% of Average Aggregate Consumption - Summer			
1	26	22	24
2	26	22	22
3	26	22	25
70% of Average Aggregate Consumption - Winter			
	LL	70%	70%
1	81	72	72
2	106	94	75
3	141	125	103

The quantities advocated by SoCal will result in a less radical change from lifeline. The SoCal-proposed quantities will be adopted.

We turn now to the question of computation of the first-tier rate. The specific issue is whether the customer charge revenue should be included when calculating the discount baseline rate which is to be 15% to 25% below the system average rate.

TURN argues for inclusion of the customer charge revenues when calculating the baseline rate and staff recommends its exclusion.

While we believe that the intent of baseline is to afford protection from the full impact of rate increases for at least 50% of the residential consumption we do not believe that this precludes us from establishing a reasonable customer charge. In this decision we have adopted a customer charge based on certain customer related expenses such as billing and meter reading. With this type of customer charge and the baseline rate set 15% to 25% below the system average rate residential customers are provided adequate protection from the full impacts of rate increases on their basic usage.

The next logical issue is if there should be a customer charge and if so, at what level. SoCal recommends that the customer charge be increased from the present \$3.10 to \$6.46. SoCal argues that the embedded cost of service to directly service a customer is \$10.23 and that the present \$3.10 charge was first established in

1977. SoCal also attempts to show that a customer charge provides for revenue stability. SoCal also argues that residential rates are high enough with a customer charge to provide a conservation incentive.

TURN notes that SoCal's proposal is based on a fully allocated cost of service standard which we have rejected many times. But even within this term of reference TURN shows that at the present $3.10 level residential customers are paying the highest percentage of the allocated cost of service customer costs of every customer class on the system. TURN also shows that the revenue stabilization aspects results in only a 5% impact. Also, the level payment plan contributes to revenue stability.

The staff proposes retention of the existing $3.10 customer charge. Staff witness Ferraro does not rely on the company's cost allocation study, but rather suggests that a residential customer charge should be "identified as recovering specific costs associated with customer services such as billing, postage, and meter reading." Only variable, out-of-pocket costs would be included under staff's theory, not fixed or sunk costs. Customer understanding and acceptance also play a major role in staff's thinking on the issue. The staff concludes that the existing $3.10 customer charge should be retained.

TURN submits that if there is to be any residential customer charge, staff's approach is far superior to SoCal's. It would be more economically appropriate if such a charge were related to the marginal cost of serving the customer each month. Staff's method relies on an average variable cost rather than marginal cost. Still, in TURN's view, this is closer to an appropriate price than the allocation of fixed costs used by SoCal.

We will adopt the staff recommendation. It appears that there is good customer acceptance of the customer charge at this level which would probably not be there at higher levels. In addition there appears to be a good possibility of the need for a customer-type charge in the staff's long-range rate policy. We prefer not to eliminate the customer charge at this time if there is any probability of reinstituting it in the near future.

The next residential rate structure issue is the number of tiers. In the spring CAM, SoCal proposed a two-tier rate structure to be consistent with PG&E's two-tier structure in northern California. The staff also proposes a two-tier structure. TURN also supports a two-tier structure for rate simplification. No other party contested this issue. We will adopt the two-tier structure at this time. Although it would seem logical to await implementation of baseline in May, we believe that it is more appropriate to change structure when there is a rate reduction assured.

The last residential rate design issue is whether or not lifeline/baseline allowances should be extended to residential hotels. The staff has proposed the extension on the same terms and conditions as are applicable in PG&E tariffs.

SoCal opposes extending baseline allowances to residential hotels in the manner that PG&E has. PG&E's tariff does not extend the baseline allowance to similar establishments such as retirement homes and dormitories. More substantively, however, the extension to hotels and other establishments would be extremely difficult to monitor and administer. The record in this case did not investigate the administrative burden that would be created by extending the baseline allocation to residential hotels and similar types of institutions. SoCal believes that the Commission should issue an OII to address the problem.

We will adopt the staff recommendation. We have not been made aware of any difficult administrative problem in extending these rate in northern California. We believe that similarly situated customers should be treated in a like manner.

Implementation of the baseline allowances on May 1, 1985 will shift an estimated 131,723,000 therms from Tier I to Tier II; this will create a $37,687,000 revenue increase based on the adopted sales for this CAM period. To offset this increase we will adjust the residential rates on May 1, 1985; the baseline rate will be 41.5¢/therm and the non-baseline rate will be 78.1¢/therm. This sets the baseline rate at 77.6% of the SAR (PU Code Section 739(c) sets the rate at 75% to 85% of the SAR) and retains the residential revenues at the adopted level.

2. Wholesale Capacity Charges

Wholesale capacity charges were proposed by SoCal which contained the percent of adopted margin to be assigned to SDG&E and the City of Long Beach as annual capacity charges. The proposed capacity charge factors for SDG&E and the City of Long Beach, respectively, are 2.0881% and 0.6166% of total margin. These capacity charge factors were developed using the Base Supply and Load Equation (BS&LE) cost allocation methodology. Development of an annual percentage of margin figure, reflecting the BS&LE cost study methodology, was approved in the last two SoCal general rate case decisions, and staff supports this recommendation, which neither Long Beach nor San Diego opposed. With this agreement, we will adopt the SoCal proposal.

3. Short-Term Rates

With most rate structure issues settled, we will now turn to our specific rate policy for this case. Our present rate policy is contained the above discussion regarding long-term policy. Because the staff's proposal is furthest from our present policy, we will discuss it first. The staff's proposal contains the following recommendations:

1. It is not appropriate that some rates be increased when others are decreased.
2. Rate targeting is undesirable.
3. Target rate for water pumping is appropriate.
4. Target rate for enhanced oil production is appropriate.
5. Target rate for food processing is not appropriate.
6. All No. 6 alternate fuel customers should face the same rate. (Indexed No. 6 rate.)
7. Maintain GN-5 rates at present levels.

These recommendations lead to rates in which all No. 6 alternate rates are lowered to be equal to the GN-5 rate (46.329) and the special GN-34 and GN-6 rates are phased out. Staff recommends that the EOR rate be set at 38¢. This entire set of recommendations is conditioned on the use of a 12-month amortization which would allow some minor reductions in the remaining residential and commercial rates. Staff has no consistent theoretical basis for these recommendations but feels that industrial rates are too high and oil producers should be given the incentive that lower gas prices will result in lower industrial rates and therefore greater sales.

SoCal's proposal essentially continues our present policy with some fine tuning. The fine tuning is accomplished by the following:

1. Lower the index bases of alternate fuel customers to be somewhat lower in the range of fuel oil prices.

2. Bring the commercial average rate closer to the residential average rate.

3. Continue food processor rates at present levels.

4. Continue the GN-5 (UEG) rates at present levels.

5. Adopt a GN-21 rate at 54¢/th for water pumping.

6. Lower the EOR rate to 38.3¢ and allow it to float at SoCal's discretion.

The theoretical basis underlying the SoCal proposal is essentially the same as underlies our present policy. The primary deviation is that SoCal proposes the lowering of alternate fuel industrial rates even though reducing such rates produces no increase in margin contribution. SoCal's rationale is to provide an incentive to gas producers.

TURN puts forth the most straightforward proposal. TURN indicates that past implementation of our present policy has resulted in rates that bear a reasonable relationship to one another. Therefore, an equal cents per therm or equal percentage reduction is most appropriate. In TURN's view continuation of our present policy would lead to greater residential reductions but TURN agrees that a signal must be sent to producers. Finally, TURN argues that an equal cents per therm adjustment for future increases and decreases would be a proper transition until we complete a long-term rate design examination as proposed by the staff. With total sales of 9,441,843 Mtherms and a total rate reduction of about $114 million, application of TURN's methodology would produce about a 1¢/therm reduction.

CMA proposes further reductions for the industrial customers than proposed by staff. The University of California supports the staff proposal particularly as it relates to the reduction of the GN-34 rate to the level of the other No. 6 fuel oil alternate rates. Other representatives of various agricultural customers and water districts support the new special waterpumping rate.

The last substantial proposal in this proceeding was put forth by Kimberly-Clark and Simpson Paper Company. Kimberly-Clark sees a problem in our rate design in that we only recognize two types of alternate fuel oil - No. 2 and No. 6. These customers are disadvantaged in that the intermediate fuels are less than the price of No. 2 fuel oil, but we fail to recognize this with our current rate schedules with the result that these customers are forced to leave SoCal's system. Kimberly-Clark recommends that we adopt a new rate schedule to recognize the burning of a blend of fuel oils somewhere between No. 2 and No. 6, or in the alternative Kimberly-Clark recommends that the alternate fuel gas rates accurately reflect actual alternative fuel prices.

Discussion

No party has shown any major defects in our present policy with the exception that it fails to send a proper price signal to gas producers. We agree with TURN that an equal cents per therm change in rates will maintain present relationships while sending the message to producers that changes in the cost of gas will be shared by all customers. Based on these concepts we will adopt rates that provide that residential, commercial, and industrial classes, on the whole, will share equally in the current reduction by an equal cents per therm reduction.

Within the industrial class the GN-32/42, GN-36/46, GN-34, GN-5, G-COG, GN-6, GN-7, and ammonia rates will be afforded slightly different treatment. Parenthetically, we note that all customers on indexed rates will continue to gain a benefit as the oil market continues to soften. The benefit is reflected in a reduced contribution to margin which must later be picked up by other customers. Within this class there presently exist certain special low indexed rates - Ammonia Producer, GN-5, GN-6 and GN-7. These rates are either set by statute or are indexed based at the lowest reasonable level of the alternate fuel prices. While we recognize that the GN-5 is indexed independently, the forecast GN-5 rate is used to generate the revenue requirement. The rate tables that follow this discussion recognize that the GN-5 rate is currently different than the rate projected by SoCal and the staff for both the present and forecast rates. Therefore, the GN-6a and GN-6b rates will remain unchanged while the GN-5 rates change in a minor fashion as shown in Table 9. The GN-5 episode day rate will be set as the average retail rate and will reflect the reduction. G-COG rate for co-generators will continue to be set at the same level as the GN-5 rate on average. The Ammonia Producer rate is set by statute at 36.5¢/therm.

Within the commercial and industrial classes, staff proposed that the customer charge be increased on the same basis as the $3.10 residential customer charge was recommended. SoCal also recommended an increased customer charge for these customers but not as large as staff. We will adopt the staff's recommendation as follows:

GN-3 and 4	$75	GN-1	$10
GN-5	$500	GN-2	$50

This additional customer charge revenue, together with the additional revenue remaining in this class by holding the special indexed rates constant, provides sufficient revenue to generate a reduction in the remaining GN-3 and 4 rates. We also agree that the GN-34 rate's initial tier should be set at the same level as the GN-36/46 rate. The GN-32/42 rates will be reduced by lowering the current rate of 56.776¢/th by the system average cents per therm reduction. The remaining revenue will be used to lower the GN-36/46 and GN-34 rates.

The GN-36/46 rates will no longer be indexed to the price of No. 6 fuel oil; rather, these rates will be initially targeted to be 5¢ below the GN-32/42 rates. The GN-34 rates will be treated similarly, that is, the initial tier will be set equal to the GN-36/46 rates with the next tier to be 5¢ lower and the third tier 2¢ below the second tier. However, neither the GN-36/46 nor any tier of the GN-34 rate will be allowed to be below the GN-5 nonepisode day rate nor above the indexed GN-32/42 rate. The present revenue requirement produces GN-36/46 rates and all three tiers of the GN-34 rate equal to the GN-5 rate. In similar fashion these same guidelines would be applied for rate increases.

The sequence for establishing the industrial rates is as follows: The indexed and special GN-5, GN-6, NH3, and GN-7 rates are determined and are not adjusted. Preliminarily, the GN-32/42 rates are set at their index level and the GN-36/46 and GN-34 Tier I are set 5¢ less. The next step is to apply the class average rate change to the GN-32/42 and the GN-34 and GN-36/46 rates either up or down. If at this point there is excess revenue then these rates are lowered equally until the floor (GN-5 rate) is reached. Any additional excess revenue is allocated to the residential and commercial customers.

If, on the other hand, there is a revenue deficiency, then the GN-32/42 rate is increased by the class average rate change with the GN-36/46 and GN-34 set 5¢ less. Further revenue deficiency is made up by raising the GN-34 and GN-36/46 rates until these rates are at the level of GN-32/42 indexed rates. Any additional revenue requirement would be made up from the residential and commercial customers. Table 9 at the end of this discussion develops adopted rates at the adopted revenues. Table 10 shows the rates that would result if there were a subsequent $60 million revenue requirement increase using the guidelines adopted herein.

Within the residential class, the class revenues will be reduced by the equal cents per therm. The Tier I rate will be set at 85% of the system average rate with the customer charge revenue included in the calculation. The second tier will be set residually.

We recognize the importance of the legislative mandate that the rate for baseline quantities be established at a differential of from 15% to 25% below the system average rate. To date we have only been able to reduce the baseline rate to a 15% differential to prevent increases to low priority customers where fuel switching has been a substantial problem. If conditions change favorably, it is our intention to move baseline differential closer to the midpoint of the range (20%).

Wholesale rates will be set by our previously adopted formula which reflects the overall reduction. The table below represents our estimates of rates proposed by SoCal and staff at our adopted revenue requirement compared to the adopted rates.

Table 8

SOUTHERN CALIFORNIA GAS COMPANY
Comparison of Proposed Rates

NOVEMBER 1984, CAM
9-MONTH AMORTIZATION

CLASS OF SERVICE	COMMODITY RATES IN ¢/THERM PRESENT RATES	SOCAL RATES	ALJ RATES	PSD RATES
RESIDENTIAL				
LIFELINE	46.468	46.468	45.609	45.609
NONLIFELINE	75.109	69.363	74.200	74.200
Average	59.576	57.938	58.703	58.703
COMMERCIAL - INDUSTRIAL				
GN-1	71.824	69.483	69.742	70.915
GN-2A	71.824	69.483	69.742	70.915
GN-2B	62.140	62.230	62.14	62.140
GN-CDG	48.868	48.888	48.764	48.175
GN-32/42	58.157	58.159	53.588	55.867
GN-36/46	57.620	57.620	48.588	46.175
GN-34 FIRST 900 MTH	56.760	56.850	48.588	46.175
- NEXT 600 MTH	45.104	45.194	47.677	46.175
- OVER 1500 MTH	43.104	43.194	46.765	46.175
AMMONIA PRODUCERS	37.670	36.500	36.500	36.500
GN-21		54.000	—	—
GN-6A	48.000	48.000	48.000	46.175
GN-6B	44.000	44.000	44.000	46.175
GN-7	40.000	40.000	38.000	38.300
ELECTRIC UTILITY GENERATION				
GN-5 NON-EPISODE DAY	46.765	46.765	46.765	46.175
GN-5 EPISODE DAY	56.686	56.776	55.614	55.614
WHOLESALE				
G-60	40.587	38.424	38.424	38.424
G-61	40.121	38.080	38.080	38.080

C. More Specific Rate Design Issues

1. GN-34

As the previous table shows tiers two and three have been set equal to the GN-5 indexed level. Under different circumstances, the second block could be about 5¢ below the initial block with the third block 2¢ less. This follows the rates suggested by SoCal and appears reasonable.

2. GN-21 Waterpumping Rate

This rate is proposed by SoCal to be applicable to gas engines used for water and sewerage pumping. The rate is supposed to retain the existence of these engines. SoCal projects that this rate would be cost-effective over a 15-year period. SoCal testifies that waterpumping by gas engines is more efficient than electric motors computed at the point of generation. Staff, together with several waterpumping districts and agricultural users, supports this rate.

Staff generally opposes special target rates and yet supports such a rate even though it would not be cost-effective in a period of less than 15 years. In light of the general support for this rate at 54¢/therm with no opposition, we will adopt the SoCal proposed rate.

3. Ammonia Producer Rate

Both CMA and PG&E have taken exception to the method proposed by applicants for establishing the ammonia producer surcharge. Most of these concerns may be answered by reviewing Section 741 of the Public Utilities Code, which established the surcharge.

Section 741(b) states:

> "If the commission determines that the difference in revenues collected by gas corporations on natural gas sales to ammonia producers...and the revenues which the gas corporations would otherwise collect on natural gas sales to ammonia producers under the rates in effect on December 31, 1983, is an amount less than the total revenues which gas corporations collect on natural gas sales to ammonia producers, the commission shall

establish a rate recovery mechanism by placing a uniform surcharge on sales of natural gas to ratepayers by every gas corporation equal to this difference."

The plain language of the statute makes it clear that the surcharge should be based on the rates in effect on December 31, 1983, not on the formula used to establish those rates as proposed by CMA. Applicants' proposed ammonia producer rates and the related surcharge are consistent with the statute, and are adopted.

4. Kimberly-Clark and Simpson Paper

Under SoCal Gas' existing P3 and P4 tariffs, two categories of alternative fuels are recognized - No. 2 fuel oil and No. 6 fuel oil. Customers using fuel oils with a viscosity higher than 150 Saybolt Seconds Universal (SSU) at 100 degrees F are billed under the GN-36/46 schedule and all other usage is billed under the GN-32/42 schedule. Thus, customers who are using intermediate or blended oils - those between No. 2 and No. 6 - are currently billed at the GN-32/42 rate which theoretically reflects the price of standard No. 2 fuel oil. Since the price of the intermediate oils is less than the price of the standard No. 2 oil, customers using these oils have been or are being lured into using alternative fuels.

In addition to setting existing rates to reflect alternative oil prices, Kimberly-Clark and Simpson Paper have asked the Commission to establish an intermediate rate, GN-34/44, which would reflect the price of the intermediate oils and would thus attract back or retain on the gas system this intermediate fuel oil market. We agree. By attempting to set gas rates of all industrial customers at their alternative fuel prices, the Commission can establish an across-the board approach to addressing industrial fuel switching. It can also avoid pressure to adopt additional "targeted" rates. While in the long term we recognize that gas rates might be set using alternative bases, in the short term the Commission will be able to treat consistently all customers facing the pressures to fuel switch.

Rather than create a new category of service, however, the Commission prefers to redefine SoCal Gas' existing categories of service. Instead of billing customers using intermediate oils under the GN-32/42 schedule, the Commission finds that these customers should be billed under the GN-36/46 schedule. This can be accomplished by changing the qualifying language in the GN-3 and GN-4 schedules to read "Natural gas used in facilities capable of burning on a regular basis, fuel oil with a viscosity higher than 32.6 Saybolt Secoinds Universal (SSU) at 100 degree F and an American Petroleum Institute gravity of 22 degrees or lower, petroleum coke ...." The above requirements have been set to reflect the point at which customers using intermediate oils have actually fuel switched. It represents approximately a 60/40 blend of No. 2/No. 6 fuel oil.

There are several advantages to this approach. First, customers using intermediate oils can be attracted back or retained on the gas system without adopting a new rate category. This avoids the complexities involved in setting and administering a new rate. Also, customers using intermediate oils who will not return to the gas system at the GN-32/42 rate will return at the GN-36/46 rate.

Second, customers using the intermediate oils are No. 6 oil price sensitive. By opening up the GN-36/46 schedule to customers using intermediate oils, SoCal Gas can avoid the problem of these customer again leaving the system because their "blended" oil price drops somewhere between the intermediate and No. 6 oil rate. As demonstrated by both Kimberly-Clark and Simpson Paper, as customers become better versed in using the intermediate oils, they increase the No. 6 component of their oils - thus lowering their alternative fuel price. As No. 6 oil is the heavier component of the oils currently used by both Kimberly-Clark and Simpson Paper, their alternative oil price is already approaching the price for No. 6 oil. In fact, the rate we adopt today for GN-36/46 service,

(.48588 cents per therm), is almost identical to the intermediate rate proposed by Kimberly-Clark and Simpson Paper. Thus, it is appropriate that intermediate oil customers be allowed to use GN-36/46 rate if they are to be retained on the gas system.

5. GN-3 Applicability Clause

We directed SoCal to examine the GN-3 applicability clause governing the rate for gas turbine in D.84-04-117. Applicants examined this applicability clause and recommend that no change be made to the existing language. Changing the rate for gas turbine use from the GN-5 level to the GN-32 level will result in lost sales in the short term followed by long-term permanent loss of this market. It is likely that this market would be lost to out-of-state coal purchaser by the UEG market and to purchased power, to the long-term detriment of all of SoCal customers. Staff concurs. No other party contested this issue. The applicants' proposed retention of this clause is adopted.

6. GN-5 Rates (UEG)

The GN-5 nonepisode day rate is presently indexed to the price of fuel oil. The index base is at the low end of the oil price range. There is no need to change this rate at this time. The episode day rate is set at the average retail rate. There was not sufficient record evidence to warrant a change of this standard. The rate will be changed to reflect the reduced average retail rate.

7. GN-6 Rates

Applicants have proposed the continuation of the GN-6 rate schedules for food processors. These rates were first proposed in the May 1984 CAM because food processors were identified as a group with a history of significant fuel switching, and one which would produce increased economic benefits to the entire gas system if a lower rate could attract and hold additional customers. In the May 1984 CAM we adopted the proposed rate of 44¢/th for food processors located outside the South Coast Air Quality Management District (SCAQMD) and 48¢/th for those located inside the district. The difference between the two rates is based on a difference on the alternate fuel prices available to food processors inside and outside the SCAQMD. These rates are to continue in effect until discontinued or modified by order of the Commission, under Resolution G-2605 (November 7, 1984).

Staff recommends the elimination of end-use rates based upon the premise that all No. 6 fuel oil gas rates will be lowered significantly. We have not reduced the GN-36/46 rates as low as recommended by staff.

The rates have been extremely successful in recapturing and maintaining food processor customers. On an annual basis, sales under the food processor rates are currently 2.6 Bcf for GN-6A and 3.2 Bcf for GN-6B. If the food processor rates do not continue throughout the forecast period, applicants expect that a large portion of this load, which is in fact regained fuel switching, will return to the use of fuel oil. There has been no additional fuel switching by these customers since the implementation of the food processor rates. Elimination of these rates, particularly the GN-6B rate, would be to the detriment of all of SoCal's customers because of the loss in margin which would result. A continuation of the GN-6 rates as proposed in this proceeding is to the benefit of all customers on the SoCal system, is reasonable, and is adopted.

8. GN-7 Rate

Applicants have proposed that the GN-7 rate for service to the enhanced oil recovery (EOR) market be modified to provide flexibility to SoCal in serving this market. SoCal presently offers a 40¢/th rate to EOR customers. Sales at this rate have been negligible when compared to the potential market of 100 MMcf/d for customers currently exempt from FERC incremental pricing guidelines.

Under applicants' proposal, the GN-7 rate would be determined by SoCal on the basis of:

1. Anticipated cost and availability of gas;
2. Cost of transporting gas;
3. Prices of alternate fuels; and
4. A reasonable minimum margin.

Under these criteria, the GN-7 rate as calculated by SoCal would be set initially at 38¢/th. This rate is likely to capture significant volume in the EOR market. A 38.3¢ rate would reflect a 5¢ economic benefit over the applicants' avoidable cost of gas during the forecast period.

Staff opposes the flexibility of the SoCal proposal. Staff does however support the 38¢ rate even though this represents an exception to our rule that all rates (except ammonia producer rate) should be at least 5¢ over the commodity cost of the swing source.

We will authorize a rate of 38¢ as this corresponds with the rate currently authorized for PG&E. We are confident that this rate will allow SoCal to effectively compete in this potentially lucrative market and allow them to capture significant volume which will contribute substantially to the present undercollection in the CAM balancing account. We will deny the flexibility requested by SoCal as it is too broad in that the company has failed to include even a specific rate charge mechanism for our review.

9. <u>Master Meter Discount</u>

PU Code Section 739.5(a) requires that a master meter customer receive a discount to recover the reasonable average costs for providing a submetered service to individual residential units, and that a master meter customer charge each submetered user the same rate as if the submetered user were receiving a service directly from the utility.

SoCal Tariff Schedule GS-Multifamily Service Submetered provides for a discount of 10% of the revenues from lifeline sales. The master meter owner bills each tenant a customer charge in accordance with PU Code § 739.5(a). SoCal bills the master meter owner one customer charge. Thus, the master meter owner is provided the discount plus the monthly customer charge. This 10% discount is based on the number of tenants times the lifeline allowance. If a tenant does not use the total lifeline allowance, the master meter owner would still get the discount. The monthly customer charges collected by the master meter owner equal the total number of tenants less one. The 10% discount for lifeline revenues plus the monthly customer charge approximates $5.40 per unit based on 1982 recorded data at present rates.

In this proceeding, staff recommends a flat discount of $5.40 per unit. Both SoCal and ~~Western Mobilehome~~ Association concur in this recommendation. This recommendation is consistent with recent decisions for other utilities and will be adopted.

10. Standby Service

Staff first raised this issue in the spring CAM. We deferred consideration giving SoCal additional time to analyze this issue. SoCal has analyzed the issue of providing standby service for commercial and industrial customers, and has proposed to offer service to customers who use gas either on a regular basis or on a standby basis. Standby service will be provided under existing rate schedules. This service is proposed because customers who come on the system as standby customers may begin regular service in the future with resultant contribution to margin.

SoCal argues that while service will not be unreasonably denied, it is necessary that it reserves the right to deny standby service. Standby service might be denied if a customer needs a large volume of gas, but needs it only once per year. This type of service would not be cost-effective. Furthermore, it could create storage and supply operating difficulties for SoCal and PLGS. Other examples of instances where service could be denied would be where a customer in a low pressure area of the distribution system seeks a large quantity of gas which would threaten system integrity or instances where the customer and the company cannot come to terms on payment for the installation of facilities necessary to serve the customer.

Staff proposes that standby service be provided at the highest commercial rate and that the customer pay for any additional facilities required.

We will adopt the SoCal proposal as being easier to administer. We do direct, however, that SoCal confer with our staff whenever a denial of service is contemplated.

11. System Average Rate

Another issue concerns the calculation of the system average rates. This calculation is used to determine the baseline rates.

In a recent PG&E decision ~~D.84-08-116 we~~ adopted a procedure for calculating the SAR. That method used the operating revenues less the master meter discount and the total sales including the adjustment for employee discount. SoCal has only a sales adjustment for the master meter discount; the staff has excluded the master meter discount. SoCal's operating revenues include exchange revenues which are contained in the authorized gas margin. The SAR then becomes the operating revenues divided by the total sales. This procedure has been utilized by the staff in this proceeding in order to conform with the intent of D.84-08-116.

TURN, on the other hand, argues that approximately $17,677,000 of "other operating revenues" is improperly included. TURN further argues that the result is a system average revenue rather than system average rate. The effect of the two different calculations is a difference of about .2¢.

We agree with the staff that the calculation should include other operating revenues. Our agreement is based on simplicity. We believe that the SAR should be calculated with few, if any, adjustments and that ideally it is produced by dividing the total revenue requirement by the total sales. The staff's estimate is adopted.

12. Forecast Indexed Rates

Another issue carried over from the spring CAM is whether the CAM revenue requirement should be calculated using the rates currently in effect for indexed rates or whether the indexed rates should be forecast over the future CAM period. SoCal and TURN recommend use of forecast indexed rates whereas the staff recommends the use of rates currently in effect.

Forecast indexed rates are currently used for PG&E. The staff recommendation is based on the fact that the use of current rates eliminates a potential issue to be contested. Staff attempts to show that the use of current rates will not result in significant errors.

We are looking for as accurate an estimate of future revenues as possible in the CAM proceedings to avoid severe over/undercollections. The staff and SoCal may use either method but we prefer the use of forecast indexed rates.

13. Marginal Cost of Gas

We will adopt the uncontested testimony of the staff in the general rate case A.84-02-025 that the marginal cost of gas for SoCal is the cost of the alternate fuel of SoCal single largest customer with alternate fuel capability.

While we adopt this concept we are not yet satisfied with the entire record on marginal cost. Other concepts that we would like to see explored are the market clearing price as a measure of marginal cost. Another concept is that marginal cost equals marginal operating cost plus a shortage cost. We would hope to see some discussion of whether the costs of gas storage might represent a shortage cost.

It has become apparent over the very recent past, that SoCal presently lacks in-house academic expertise regarding gas marginal costs (producer, supplier, and distributor) and rate design. We urge SoCal to consider remedying this so that the upcoming long-term rate design proceeding will have the same high level quality of participation as did this proceeding on sequencing.

14. Prorationing

The Commission has adopted for Edison in its general rate case decision implementation of daily Baseline allowances and a change from monthly to daily rates. These methods will simplify the prorationing calculations and in turn should enhance customer understanding of the procedure. The Commission by Resolution No. G-2593 dated April 18, 1984 has approved a change from monthly to daily rates for SoCal Gas.

The service territories of SoCal Gas and Edison are, for the most part, coterminus or adjacent. Many SoCal Gas customers are Edison customers or vice versa.

Thus it would appear reasonable to have a similar type of billing and prorationing for each utility. This would be beneficial to customer understanding of utility bills. We therefore authorize SoCal Gas to file for daily Baseline allowances with proration to be effective May 1, 1985.

D. Rate Tables

TABLE NO. 9

SOUTHERN CALIFORNIA GAS COMPANY

12 MONTHS BEGINNING NOV 1, 1984

SUMMARY OF RATES AND REVENUES

Line No	Classification	Non-therm Units (1000's)	Sales (Mth)	Present Rates ($/unit)	Present Revenues (M$)	Adopted Rates ($/unit)	Adopted Revenues (M$)	Increase (%)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Residential							
1	Customer Months	45794		3.1	141961	3.1	141961	.00
2	Tier I (Lifeline)		2052854	.46468	953920	.45463	933289	-2.16
3	Tier II		547121	.75109	410929	.74074	405267	-1.38
4	Tier III		271328	.75109	203791	.74074	200983	-1.38
5	Total Residential		2871293	.59576	1710601	.58562	1681500	-1.70
	Commercial-Industrial							
6	Customer Months				13048		26951	106.55
7	GN-1		931360	.71824	668940	.69742	649549	-2.90
8	GN-2A		189780	.71824	136307	.69742	132356	-2.90
9	GN-2B		72866	.6214	45278	.6214	45278	.00
10	GN-32/42		406441	.56776	230760	.53589	217803	-5.61
11	GN-36/46		346704	.56776	196844	.48589	168456	-14.42
	GN-34							
12	Blk 1		32400	.5676	18390	.48588	15742	-14.40
13	Blk 2		12207	.45104	5505	.46303	5652	2.67
14	Blk 3		9902	.43104	4268	.46303	4584	7.40
	GN-5/50							
15	Regular		628750	.56686	356413	.55421	348459	-2.23
16	Indexed		2337982	.46239	1080591	.46303	1082555	.18
17	G-COG		107122	.48437	51886	.48233	51670	-.42
18	NHS Producer		68886	.37677	33483	.365	32443	-3.11
19	GN-21		0		0	.54	0	.00
20	GN-6A		27113	.48	13014	.48	13014	.00
21	GN-6B		33965	.44	14943	.44	14943	.00
22	GN-7		0		0	.38	0	.00
23	Total Coml-Indl		5225476	.54917	2869670	.53765	2809455	-2.10
24	GS Exclusion*		6562					
25	Total Retail		8103331	.56523	4580271	.55421	4490955	-1.95
	Wholesale							
26	G-60 Cap Chg				4781		7040	47.25
27	Comm Chg		281301	.40587	114171	.38423	108084	-5.33
28	G-61 Cap Chg				23072		23659	3.02
29	Comm Chg		1057211	.40121	424163	.38067	402448	-5.12
30	Total Wholesale		1338512		566187		541431	
31	Subtotal Revenues		9441843	.54507	5146458	.53299	5032365	-2.22
32	Other Revenues, Exchange & NHS Adj.				15369		17677	
33	Operating Revenues		9441843	.5467	5161827	.53486	5050043	-2.17

Table 10

SOUTHERN CALIFORNIA GAS COMPANY

Illustrative Rates With Hypothetical
60 Million Increase

SUMMARY OF RATES AND REVENUES

Line No	Classification	Non-therm Units (1000'S)	Sales (Mth)	Rates ($/unit)	Revenues (M$)	Rates ($/unit)	Revenues (M$)	Increase (%)
	Residential							
1	Customer Months	45794		3.1	141961	3.1	141961	
2	Tier I (Lifeline)*		2052854	.45609	936286	.4599	944107	.84
3	Tier II		547111	.74074	405267	.75716	414261	2.22
4	Tier III		271328	.74074	200983	.75718	205444	2.22
5	Total Residential		2871293	.58667	1684497	.59408	1705773	1.26
	Commercial-Industrial							
6	Customer Months				24951		24951	0
7	GN-1		931360	.69742	649549	.70483	656456	1.06
8	GN-2A		189780	.69742	132356	.70483	133762	1.06
9	GN-2B		72800	.6214	45278	.6214	45278	0
10	GN-32/42		406441	.53588	217803	.56776	230760	5.95
11	GN-36/46		346704	.48589	168456	.51867	179824	6.75
	GN-34							
12	Blk 1		32400	.48589	15742	.51867	16804	6.75
13	Blk 2		12207	.47677	5819	.49312	6020	3.45
14	Blk 3		9902	.46765	4630	.46765	4630	0
	GN-5/35							
15	Regular		628750	.55614	349673	.56355	354332	1.33
16	Indexed		2337962	.46765	1093357	.46765	1093357	0
17	G-COE		107122	.4864	52104	.48797	52272	0.32
18	NH3 Producer		88860	.365	32443	.365	32443	0
19	GN-21		0	.54	0	.54	0	0
20	GN-6A		27113	.48	13014	.48	13014	0
21	GN-6B		33963	.44	14943	.44	14943	0
22	GN-7		0	.383	0	.383	0	0
23	Total Coml-Indl		5225476	.54007	2822118	.54746	2860640	1.37
24	GS Exclusion*		6562					
25	Total Retail		8103331	.55614	4506615	.56355	4566613	1.33

Findings of Fact

1. By this application SoCal requests authority to reduce rates under its consolidated adjustment mechanism tariff clause by $145.6 million on an annual basis.

2. The staff's sales figure is reasonable.

3. Contract constraints in the past have resulted in improper market signals from the consumers to gas producers.

4. The FERC 380 series of orders has reduced supplier-distributor contract constraints.

5. Sequencing gas takes by distributors can aid the transmission of price signals from consumers to distributors.

6. Incremental price sequencing of gas takes by distributors send a more accurate price signal to producers than average cost sequencing in cases where the different suppliers have widely varying cost structures.

7. Incremental price sequencing in enhancing the price signal to producers tends to reduce the price signals to suppliers (pipelines).

8. It is reasonable to have a price window in which takes of gas from producers are on other than strictly incremental pricing.

9. A price window of 1.0¢/th is reasonable.

10. The cost of gas developed on Table 3 herein is reasonable.

11. It is reasonable to amortize the balancing account over a 9-month period.

12. Development of the CAM revenue requirement should reflect the decision in the general rate increase application A.84-02-025.

13. A revenue requirement decrease of $97,875,000 is reasonable.

14. It is reasonable to have a two-tier rather than three-tier residential rate structure.

15. The baseline quantities developed herein at page 35 are reasonable.

16. No good and sufficient reason currently exists to either reduce or increase the customer charge.

17. It is reasonable to apply rate decisions and increases to the residential, commercial (GN-1 and 2) and industrial customer (all other retail rates) on an equal cents or equal percentage charge to those three customer classes as a whole.

18. Special low indexed rates will not participate in rate decreases on the equal cents-per-therm basis.

19. In general special target rates based on value of service and contribution to margin are undesirable.

20. Opening the category of customers who can use GN 36/46 rates is reasonable.

21. Lowering the current EOR (GN-7) from 40¢/th to 38¢/th is reasonable.

22. A flat master meter discount of $5.40 per unit is reasonable.

23. It is reasonable to include "other" revenues in the calculation of the system average rate.

24. Due to the proximity of the service territories of SoCal Gas and Edison and for customer understanding of utility bills, SoCal Gas and Edison should utilize similar types of billing and prorationing.

25. The baseline quantities developed herein at page 35 with an effective date of May 1, 1985 are reasonable.

26. Baseline quantities will shift an estimated 131,723,000 therms to the non-baseline sales and increase revenues.

27. Revising the residential rates to 47.56¢ for baseline sales and 78.71¢ for non-baseline sales will offset the revenue increase and retain the adopted residential revenues.

Conclusions of Law

1. The rates set forth in Appendix B are just and reasonable for the period these rates will be in effect.

2. The application to reduce rates should be granted to the extent provided in the above Findings.

INTERIM ORDER

IT IS ORDERED that on or after the effective date of this order, Southern California Gas Company is authorized to file revised tariff schedules reflecting the rates attached as Appendix B. The revised tariff schedules shall take on the date of filing or January 1, 1985 whichever is later. Rates shall apply to service rendered on or after the effective date of the tariffs.

This order becomes effective 10 days from today.

Dated December 28, 1984, at San Francisco, California.

I will file a concurring opinion.

/s/ VICTOR CALVO
Commissioner

I dissent in part.

/s/ PRISCILLA C. GREW
Commissioner

DONALD VIAL
President
VICTOR CALVO
PRISCILLA C. GREW
WILLIAM T. BAGLEY
FREDERICK R. DUDA
Commissioners

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

Joseph E. Bodovitz, Executive Director

APPENDIX A

LIST OF APPEARANCES

Applicants: E. R. Island, Jeffrey C. Jackson, and Frederick E. John, Attorneys at Law, for Southern California Gas Company and Pacific Lighting Gas Supply Company.

Interested Parties: H. Robert Barnes and Richard K. Durant, Attorneys at Law, for Southern California Edison Company; J. David Hanson, Attorney at Law, Daniel Hyska, David W. Anderson, and Robert L. Pettinato, for Los Angeles Department of Water & Power; John R. Asmus, Jr., Attorney at Law, for San Diego Gas & Electric Company; Peter W. Hanschen, Michael S. Hindus, and Shirley Woo, Attorneys at Law, for Pacific Gas and Electric Company; Messrs. Biddle & Hamilton, by Richard Hamilton and Halina F. Osinski, Attorneys at Law, for Western Mobile Home Association; Michel Peter Florio and Jon F. Elliott, Attorneys at Law, and Sylvia M. Siegel, for Toward Utility Rate Normalization (TURN); John D. Quinley, for himself; Steven R. Hunsicker, Attorney at Law (Washington, D.C.), and Baker & Botts, by John W. Leslie and Charles M. Darling, IV, Attorneys at Law, for Tenneco Oil Company and Conoco, Inc.; Richard Owen Baish, Attorney at Law (Texas), for El Paso Natural Gas Company; Earle H. Mowrey and Thomas C. Wagner, Attorneys at Law (Texas), and Vinson & Elkins, by James W. McCartney, for Transwestern Pipeline Company; Donald Crews, for Canners Steam Company; E. D. Yates, for California League of Food Processors; Harry K. Winters, for University of California; Gerald J. La Fave, Attorney at Law (Michigan), for California Farm Bureau Federation; Messrs. Graham & James, by David J. Marchant, Attorney at Law, for Graham & James; Messrs. Chadbourne, Parke, Whiteside & Wolf, by Jerry R. Bloom, Attorney at Law, for Kimberly-Clark Corporation and Simpson Paper Company; Messrs. Sutherland, Asbill & Brennan, by Earle H. O'Donnell, Attorney at Law, for Federal Paper Board Company, Inc.; Messrs. Downey, Brand, Seymour & Rohwer, by Phillip W. Stohr, Attorney at Law, for General Motors Corporation, Anheuser-Busch, Inc., Nabisco Brands, Inc., and Federal Paper Board Company, Inc.; Messrs. Brobeck, Phleger & Harrison, by Gordon E. Davis, Attorney at Law, for California Manufacturers Association; Henry F. Lippitt 2nd, Attorney at Law, for California Gas Producers Association; Robert W. Parkin, City Attorney, by Richard A. Alesso, Deputy City Attorney, for City of Long Beach; Charles Milan, for Long Beach Gas Department; and Graham & James, by James Squeri, Attorney at Law, for Union Oil Company of California.

Commission Staff: Arocoles Aguilar, Attorney at law, and Geoffrey W. Meloche.

(END OF APPENDIX A)

Conclusions of Law

1. The rates set forth in Appendix B are just and reasonable for the period these rates will be in effect.

2. The application to reduce rates should be granted to the extent provided in the above Findings.

INTERIM ORDER

IT IS ORDERED that on or after the effective date of this order, Southern California Gas Company is authorized to file revised tariff schedules reflecting the rates attached as Appendix B. The revised tariff schedules shall take on the date of filing or January 1, 1985 whichever is later. Rates shall apply to service rendered on or after the effective date of the tariffs.

This order becomes effective 10 days from today.

Dated December 28, 1984, at San Francisco, California.

I will file a concurring opinion.

/s/ VICTOR CALVO
Commissioner

I dissent in part.

/s/ PRISCILLA C. GREW
Commissioner

DONALD VIAL
President
VICTOR CALVO
PRISCILLA C. GREW
WILLIAM T. BAGLEY
FREDERICK R. DUDA
Commissioners

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

Joseph E. Bodovitz, Executive Director

APPENDIX B
SOUTHERN CALIFORNIA GAS COMPANY
SUMMARY OF RATES
NOVEMBER 1984, CAM

CLASS OF SERVICE	COMMODITY RATES IN ¢/THM PRESENT RATES	ADOPTED RATES	MONTHLY CUSTOMER CHARGE
RESIDENTIAL			$3.10
Lifeline (Tier I)	46.468	45.463*	
Nonlifeline (Tier II)	75.109	74.074*	
COMMERCIAL - INDUSTRIAL			
GN-1	71.824	69.742	10.00
GN-2A	71.824	69.742	50.00
GN-2B	62.140	62.140	50.00
G-COG	48.868	48.235	75.00
GN-32/42	58.159	53.588	75.00
GN-36/46	57.620	48.588	75.00
GN-34 First 900 MTH	56.760	48.588	75.00
- Next 600 MTH	45.104	46.303	
- Over 1500 MTH	43.104	46.303	
Ammonia Producers	37.670	36.500	**
GN-21	---	54.000	50.00
GN-6A	48.000	48.000	100.00
GN-6B	44.000	44.000	100.00
GN-7	40.000	38.000	500.00
ELECTRIC UTILITY GENERATION			500.00
GN-5 Non-Episode Day	46.219	46.303	
GN-5 Episode Day	56.868	55.421	
WHOLESALE			
G-60	40.587	38.423	586,667***
G-61	40.121	38.067	1,986,583***

* Tier I rate to be 41.5¢ and Tier II rate to be 78.1¢ when baseline quantities are implemented on May 1, 1985.
** Charge for regular schedule applies.
*** The annual charge is: G-60 at $7,040,000; and G-61 at $23,839,000.

(END OF APENDIX B)

A.84-09-022
D.84-12-066

VICTOR CALVO, Commissioner, concurring.

While I join the majority's opinion in this matter, I am filing this concurring opinion to express my concerns regarding the majority's treatment of the residential baseline rate.

The lifeline concept was designed to ensure the affordability of gas and electric energy to residential customers. However, lifeline quantities, originally contemplated to be the minimum level of consumption necessary to maintain a household, became the target of intense debate in rate proceedings. Those quantities were ultimately complicated by climate zone design and redesigns, specific appliance allowances, hardship allowances, and other special considerations ad infinitum. Baseline was adopted as a simplification of the old, cumbersome lifeline system but was supposed to retain the affordability and rate equity aspects of lifeline.

The "baseline", or Tier I residential, rate must, pursuant to the terms of Public Utilities Code Section 739(c) and subject to limited exceptions, be fixed "...at a differential of from 15 to 25 percent below the system average rate." The residential customers of Southern California Gas Company (SoCalGas) have for some time been paying a monthly customer charge of $3.10. While that charge has always been included in setting the differential between the now defunct lifeline rate and the system average rate, the majority today excludes that charge in setting the baseline rate differential. I am concerned that this action may have ramifications which could undermine the whole lifeline-baseline concept.

Our action subjects residential customers to rate exploitation should utilities or this Commission manipulate the level of the customer charge. Toward Utility Rate Normalization (TURN) (and Commissioner Grew through her dissent) finds this possibility so onerous that it argued that the method constitutes a violation of the spirit of the baseline legislation. However, I do not see this as a matter of law but one of policy. <u>The important aspect of today's decision is that it does take special care to protect the lifeline-baseline concept</u>. I therefore join the majority on this issue. On the other hand, although the adopted rate design preserves and implements the equitable entitlements of the residential class to its fair share of the rate decrease we today order and, more importantly, further preserves a rational relationship between the old lifeline rate structure and the new baseline rate design, it does place the lifeline-baseline concept in some jeopardy and residential ratepayers at risk in future proceedings. In this regard, TURN and I agree.

Obviously, TURN's fear, which I share, is that future Commission actions will not demonstrate the care or continue the protections embodied in today's order. Our order lays the foundation for mischief and abuse should SoCalGas next seek precipitous increases in the residential customer charge which, by our order, would not necessarily be offset by changes in the residential first tier rate. I am filing this separate opinion in order to advise the parties who follow our proceedings that I will not tolerate any attempts to use today's precedent to undermine the baseline concept. If applications to increase existing residential customer charges or to implement new charges for those utilities which do not yet have them proliferate, I will not support them and would otherwise reconsider my vote in this matter.

Today's action is in my opinion reasonable but the potential for abuse of the precedent is inherent in the decision. Utilities should not consider the decision as an invitation to increase or implement customer charges. The order issued today does not make this explicit and, therefore, I file this concurring opinion to advise parties as to my own opinion on the subject.

Victor Calvo

VICTOR CALVO
Commissioner

December 28, 1984
San Francisco, California

A.84-09-022
D.84-12-066

PRISCILLA C. GREW, Commissioner, Dissenting in part:

I dissent on the issue of the baseline rate adopted by the majority.

According to California PU Code Section 739(c), the baseline rate is to be set at between 75% to 85% of the system average rate (SAR). On page 40a of this decision, the majority asserts that it "sets the baseline rate at 77.6% of the SAR."

At first glance, this rate seems to meet the requirements of the Code. But the majority made the calculation by ignoring the customer charge of $3.10. If the customer charge is included in the calculation, as we have always done in setting lifeline rates, the majority today has in fact set the baseline rate at 90.5 percent of the SAR, in violation of the Code. In response, the majority claims that the Code does not specifically prohibit exclusion of the customer charge in the calculation. But the majority ignores the plain fact that every residential customer nevertheless must pay the $3.10 customer charge.

I agree with TURN and the ALJ in this case that inclusion of customer charge revenues is entirely appropriate in calculation of the baseline rates. This has been our traditional practice for lifeline rate calculations. We have had to set these rates for utilities with and without a customer charge. The legislation which changed lifeline to baseline did not direct us to change our practice of including the customer charge in lifeline/baseline calculations for ratesetting.

To ignore the customer charge in setting the baseline rate is to give the utilities an incentive to raise the customer charge in order to recover more revenue from residential customers using small amounts of gas. Even in the case of the $3.10 customer charge, the effect of the majority's decision is to make small users subsidize the rates of Tier II users who consume more gas, because it reduces rates for those large users. This contradicts the intent of the baseline legislation which is to keep at least a baseline minimum amount of gas affordable to all residential ratepayers in California.

I would prefer to adopt the alternative proposed by ALJ Henderson, namely to eliminate the customer charge and set Tier I rates at 85% of system average. This produces a rate structure similar to that now in effect for PG&E, and clearly meets the requirements and intent of the baseline legislation.

Priscilla C. Grew

PRISCILLA C. GREW, Commissioner

December 28, 1984
San Francisco, California