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Decision 90-11-023 November 9, 1990

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

In the Matter of the Application of the SOUTHERN CALIFORNIA GAS COMPANY for Authority to Revise its Rates Effective October 1, 1990, in its Annual Cost Allocation Proceeding.	Application 90-03-018 (Filed March 15, 1990)
In the Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY for Authority to Revise its Rates Effective October 1, 1990, in its Annual Cost Allocation Proceeding.	Application 90-03-049 (Filed March 29, 1990)

(See Appendix A for List of Appearances.)

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O P I N I O N

I. Summary of Opinion

This decision authorizes a rate increase of approximately $72,760,000 to Southern California Gas Company (SoCal) for increases in its cost of natural gas and related expenses for the period October 1, 1990 through September 30, 1991. This decision authorizes a rate decrease of approximately $17,140,000 to San Diego Gas & Electric Company (SDG&E) for increases in its cost of natural gas and related expenses, offset by overcollections in its balancing accounts. The principal dispute in the proceeding concerned the expected cost of natural gas during the forecast period. SoCal estimated an average cost of $2.50 MMBtu; SDG&E estimated $2.38 MMBtu; and Division of Ratepayer Advocates (DRA) estimated $2.21 MMBtu. All the estimates were prepared in early 1990. The decision finds that because of events subsequent to Iraq's invasion of Kuwait natural gas prices will rise over the forecast period and SoCal's estimate of $2.50 MMBtu is reasonable.

The decision finds that SoCal's rates will change as follows:

	Increase (Decrease) (000)	Percent Change
Core		
Residential	$ 89,698.3	5.45%
Other core (excluding UEG Igniter Fuel)	36,470.6	5.83%
Transport	852.8	17.87%
Core Total	$127,021.7	5.58%

Noncore		
Industrial	$ (8,134.0)	-9.29%
Cogeneration	(7,752.9)	-19.33%
UEG	(30,496.0)	-21.70%
Long-term contracts	123.9	2.65%
Wholesale		
Long Beach	$ (3,488.8)	-16.55%
SDG&E	(11,426.4)	-11.94%
Noncore Total	$(54,256.8)	-14.17%
System Total	$ 72,764.9	2.74%

A typical SoCal residential bill will increase in winter (for 80 therms) from $43.60 to $47.82 (9.77%) and in summer (for 30 therms) from $18.85 to $19.79 (5.00%).

The decision finds that SDG&E's rates will change as follows:

	Increase (Decrease) (000)	Percent Change
Core		
Residential	$(16,175.7)	-8.01%
Commercial	(2,385.2)	-3.64%
Transport	(239.6)	-18.26%
Core Total	(18,800.4)	-7.00%
Noncore		
Industrial	$ (747.1)	-7.17%
Cogeneration	(1,809.1)	-9.96%
UEG	4,214.0	11.76%
Noncore Total	$ 1,657.8	2.57%
System Total	$ (17,142.6)	-5.15%

The typical residential winter bill for SDG&E will remain unchanged at about $20 (40 therms). The typical summer bill will decrease slightly from $10.86 to $10.57 (20 therms). Typical bills will not decrease despite the overall residential rate decrease because most of the current decrease is reflected in nonbaseline rates.

Background

SoCal seeks to increase its rates by $120 million annually in its annual cost allocation proceeding (ACAP) and SDG&E seeks to decrease its rates by $17 million annually in its ACAP. Because the rates of SDG&E are dependent upon the rates set for SoCal we have consolidated these two matters for hearing.

The purpose of an ACAP proceeding is to adjust gas utility rates to reflect annual changes in costs. Among the principal factors considered in these proceedings are: any changes in authorized revenue requirement not previously reflected in rates; the amortization of balances in authorized balancing and tracking accounts; forecast changes in the cost of gas supplies reflected in core customer rates; forecast throughput to customers; and changes necessary to fairly allocate costs among the various customer classes for the ACAP test period. In both of these applications the ACAP test period is October 1, 1990 through September 30, 1991. In our ACAP decision for SoCal and SDG&E for the years 1989-1990 (Decision (D.) 90-01-015 in Application (A.) 89-04-021 and A.89-05-006) (the first ACAP proceeding for both of these companies) we thoroughly explored the issues that are expected to arise in an ACAP proceeding. We also said that "because of the number of major gas issues we expect to have pending before the Commission in other proceedings in 1990, we intend to streamline 1990 ACAPs as much as possible. This year's ACAPs will have to be limited to routine issues." (D.90-01-015 at p. 8.) Adhering to that adjuration and having no need to review in detail the material recently covered in D.90-01-015, the hearing in this matter was comparatively short and this decision does not require the elaboration of D.90-01-015.

On July 6, 1990 this Commission approved a long-term contract between SoCal and SDG&E which provides for a range of services, including firm transportation capacity and storage on SoCal's system. Both SoCal and SDG&E submitted late-filed exhibits

(66-C and 66-D respectively) which set forth the changes made by the contract to some of the estimates which had been introduced into evidence. This decision is based on the evidence considered in light of the contract being in effect during the ACAP period.

The differences on issues between SoCal, DRA, and other parties are relatively small considering the potential for differences in ACAPs. SoCal's most significant differences with DRA deal with the industrial demand forecast, the forecast of gas costs, and UEG rate design. The other major issue that needs to be resolved is the forecast of the capacity that will be made available by SoCal's Southern System expansion (SSE) and the cost allocation consequences of that expansion. SoCal and DRA agree on the SSE issues, but there are differences with other parties.

This decision deals primarily with issues that one or more parties disputed. Estimates of revenue, expenses, costs, balances, adjustments, etc. which were not disputed are, for the most part, not discussed, although findings of fact are made. And, in some instances, estimates are so obviously noncontroversial that neither discussion nor findings are made. They may be found only after an analysis of the appendices. Should any party desire specific findings on matters not mentioned in this decision, a request for findings, supported by citation to the record, should be made in the comments to this decision.

The parties participating and filing briefs in addition to SoCal, SDG&E, and DRA are California Industrial Group, et al. (CIG), EOR Producers/Cogenerators Trial Group (EOR Producers), Long Beach, Pacific Gas and Electric Company (PG&E), Roadrunner Club Association, Inc., et al. (Roadrunners), Southern California Edison Company (Edison), Southern California Utility Power Pool, et al. (SCUPP), Toward Utility Rate Normalization (TURN), and Western Mobile Home Association (WMA).

Public hearing was held before Administrative Law Judge Robert Barnett.

II. Alternate Fuel and Spot Gas Price Forecasts

Forecast oil and spot gas prices are key inputs essential for the development of accurate gas demand and throughput forecasts. They are necessary to determine whether fuel switching will occur, and the extent to which it will occur during the ACAP test period. They are also necessary to develop reasonable estimates of demand within customer classes, and thus are of significant importance to cost allocation.

Alternate fuel and spot gas price forecasts were developed by SoCal and DRA, and critiqued by nearly every other party appearing in the proceeding. The following average alternate fuel and spot prices were forecast by DRA and SoCal for the ACAP period:

	DRA ($/MMBtu)	SoCal ($/MMBtu)
Low Sulfur Waxy Resid. (delivered)	$3.59	$3.22
Los Angeles No. 2 Diesel	5.14	4.50
Low Sulfur No. 6	2.87	2.95
Propane	3.42	3.42
Spot Gas (California-Arizona border)	2.21	2.50

The differences between the DRA and SoCal forecasts of low sulfur waxy residual oil (LSWR), Los Angeles No. 2 diesel, No. 6 low sulfur fuel oil, and spot gas prices are a result of different forecasting methodologies, all based on forecasting oil prices. They also reflect different assumptions concerning Organization of Petroleum Exporting Countries (OPEC) actions and the effect of potential demand in Eastern Europe and the uncertainty of Soviet oil production. DRA did not independently forecast propane, but has accepted SoCal's forecast.

A. LSWR, No. 2, and No. 6 Alternate Fuels

DRA's alternate fuel price forecasts are based upon DRA's forecast price of LSWR in the Singapore market, and upon trends in the prices of No. 2 and No. 6 fuel oil. DRA forecast LSWR Singapore using several statistical methods that DRA has employed in prior Energy Cost Adjustment Clause (ECAC) proceedings before the Commission. Applying this approach, DRA forecast LSWR delivered to average $22.10/Bbl and to vary between $20 and $24/Bbl. DRA developed alternate No. 2 and No. 6 fuel prices by correlating alternate fuel prices with the forecast LSWR price using the historical price relationship of each fuel to LSWR.

SoCal's alternate fuel price forecasts, including LSWR, are based primarily upon the company's forecast of the Refiners Acquisition Cost of Crude (RACC). SoCal's RACC forecast is the RACC price forecast published in the Energy Information Administration Short-term Energy Outlook, January 1990, which is $18/Bbl. SoCal developed alternate fuel price forecasts in a manner similar to that used by DRA. SoCal's forecasts were based upon the historic relationship of each different fuel to the imported RACC. The primary difference was that SoCal used RACC prices (and spot OPEC crude prices as a proxy for RACC prices) in the correlation, whereas DRA used LSWR prices.

To compare the oil price forecasts of DRA and SoCal it is easiest to compare DRA's forecast LSWR price with SoCal's forecast LSWR price. SoCal's LSWR price was derived from its forecast RACC price. SoCal forecasts LSWR delivered to average $19.65/Bbl and to vary from $19.22 to $19.95/Bbl. This compares to DRA's forecast average of $22.10/Bbl and range of $20 to $24/Bbl.

A variety of oil price forecasts and published prices were introduced in evidence to corroborate or impeach the forecasts of SoCal and DRA. Included among this additional information were independent price forecasts of the U.S. Energy Information Administration (EIA) and Data Resources Inc. (DRI); futures market prices for West Texas Intermediate crude; and recent LSWR prices published in Platt's Oilgram.

DRI and the EIA forecast of January 1990 forecast RACC prices for the ACAP period to be $18. The subsequent EIA forecast of April 1990 forecasts RACC prices for the ACAP period to range between $19 and $20 per barrel. Relative LSWR and RACC prices have varied substantially over time. RACC prices have generally exceeded LSWR prices, but LSWR has occasionally exceeded RACC.

B. Spot Gas Price Forecast

DRA forecasts spot gas prices at the California-Arizona border (commonly called the "border price") to average $2.21/MMBtu and to vary from $2.05/MMBtu to $2.51/MMBtu during the ACAP period. DRA's forecast was developed through the use of three different models: one based upon the historic price relationship of LSWR to spot gas, and two based only upon the past history of spot gas prices.

SoCal forecasts spot gas border prices to average $2.50/MMBtu and to vary from $2.30/MMBtu to $2.89/MMBtu. SoCal's forecast is based primarily, but not entirely, upon the company's forecast RACC price and the historic relationship of RACC and spot gas prices. SoCal developed a spot gas price in this manner, and then made a judgmental adjustment to the resulting price to reflect what it believes will be the effect of the gradually disappearing surplus of gas. On this basis SoCal adjusted its spot gas price upward by 20 to 35¢/MMBtu. This adjustment results in a higher forecast price than DRA.

DRA made no such adjustment to its spot gas price, and took the position that the gradually changing supply and demand balance does not warrant making any such adjustment.

Edison forecast spot gas at $2.58 Dth based upon a judgment that spot gas prices will be rising during the forecast period over the $2.35 Dth spot gas forecast recently adopted in the PG&E ACAP (D.90-04-021 at p. 101).

C. Discussion

The current turmoil in the Middle East caused by the invasion of Kuwait by Iraq has cast a pall of uncertainty over all fuel prices and fuel price predictions. As recently as January 1990 we said that oil prices had stabilized and the energy market had firmed (D.90-01-015), but in August we issued an OII (I.90-08-006) suspending the AER mechanism for all-electric utilities, saying that the Iraqi invasion is "expected to raise prices" and that a "greater risk of price fluctuation exists in oil and natural gas markets." The guns of August (1990 style) have shot up the cost of energy.

In today's market it is an exercise in irrelevance to rely on pre-August oil and gas prices to predict near term future prices. All parties agree we must recognize the realities of the current world situation, but SoCal says speculation "based on expectations of military activities in the Middle East...is not the proper basis for an ACAP decision." DRA, citing no reasons, says that "Recent events in the Middle East and in the OPEC meetings support DRA's forecast." We agree that recent events support DRA's forecast of higher oil prices rather than SoCal's forecast; but we certainly do not agree that those events support DRA's forecast of low gas prices. And we don't believe it is speculative to conclude that the Middle East turmoil will cause fuel prices to rise.

The issue of oil prices, however, is not very important for this ACAP. At the prices of gas and oil in effect during the recent past virtually all of SoCal's fuel-switching customers have been burning gas. A further increase in oil prices will not lead to any appreciable increase in gas consumption, at least for California customers. But gas prices follow, in an imprecise way, oil prices; and gas prices are important. Therefore, because we expect oil prices during the ACAP period to be high, at least as high as the DRA forecast, we expect gas prices to be high also, at least as high as the SoCal forecast. Therefore, we will adopt an oil forecast of $3.59 MMBtu for LSWR delivered and $2.50 MMBtu for spot gas at the California-Arizona border.[1] The adopted forecast price per MMBtu for L.A. #2 is $5.14; for L.S. #6 is $2.95, and for propane, $3.42.

We are adopting our oil price forecast from DRA's forecast and our gas forecast from SoCal's forecast in the knowledge that the SoCal forecast was constructed with a strong relationship between gas and oil prices while the DRA gas forecast was based primarily on past gas prices with only a modest consideration of the relationship between gas and oil prices. We are aware that taking the oil recommendation from one forecast and the gas recommendation from the other appears anomalous. Nonetheless, we are adopting a forecast of fuel prices, not a formula, and it is our judgment that gas prices will be higher during the forecast period than DRA has forecast and oil prices higher than SoCal has forecast.

III. Core Gas Cost and Capacity Availability

A. Core Gas Cost - Long-term Contracts

The gas for SoCal's core portfolio comes from several different sources while SoCal's noncore portfolio is composed entirely of spot gas. Differences in spot gas price forecasts explain most of the difference in the forecast of core gas costs

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1 We are mindful of the problem of the self-fulfilling prophecy. By predicting a $2.50 MMBtu border price we may be promoting it; but to hedge with a low forecast could create a large under-collection, to be amortized, with interest, in later periods. This is not a desirable result. In any event, all cost forecasts are subject to this criticism.

between SoCal and DRA. Some spot gas is forecast by both SoCal and DRA to be purchased for the core portfolio. DRA has forecast considerably more spot gas purchases for the core than has SoCal, largely because SoCal has forecast that discretionary volumes under long-term contracts will be lower in cost than spot gas in many months. SoCal expects to choose between the two supplies based on their relative cost at the time of purchase. DRA also forecasts more total core demand, which it forecasts will be served with spot gas. More importantly, both SoCal's and DRA's forecasts for the price of a significant amount of gas in the long-term contracts category of the core portfolio are based on an assumed relationship of long-term supply prices to spot prices. Long-term contracts represent over half of total core supplies in forecasts by both parties. Both SoCal and DRA have forecast that the price of long-term contracts will increase by half-as-much as each party has forecast that spot gas prices will increase.

Because we have adopted SoCal's spot gas price forecast we will adopt both the SoCal price forecast and the core supply forecast for long-term contracts. The price forecast ranges between $2.48 and 2.78/Dth; the supply forecast is 243,892 MDth.

1. <u>Federal Offshore Volumes</u>

SoCal estimates it will purchase 5397 MDth for the ACAP period; DRA forecasts 4518 MDth. Both parties agree on the price forecast of $4.03/Dth.

SoCal assumes that federal offshore production will average about 14 MMcfd in 1990 and 13 MMcfd in 1991. DRA asserts that the recorded level of production from federal offshore sources has gone down by about 25% over the last year to its current level of about 10 MMcfd. DRA's estimate of 4,518 MDth is the same amount that SoCal purchased last year. Because of the decline in federal offshore production and the recorded volumes that SoCal has purchased, DRA's recommendation will be adopted.

2. <u>Core/Noncore Transfer</u>

DRA did not assume that any core to noncore transfers will take place during the ACAP period. SoCal assumes that 1108 MDth will be transferred from the core to the noncore. The differences result from minor adjustments to the computer programs used by the parties. We will adopt DRA's estimate.

3. <u>Treatment of Elk Hills Purchases and other Issues</u>

SoCal has forecast that it will purchase an average of 50 MDth per day of Elk Hills gas at a price of $2.65. By SoCal's own estimate, this price exceeds the core portfolio WACOG, the cost of "other long-term supplies," and the price of spot market gas. DRA objects to SoCal's paying a premium for Elk Hills gas, and recommends substituting spot gas for it in the core WACOG calculation. SoCal differs from DRA in that SoCal forecasts that it would pay about a 15¢/Dth premium above its forecast spot gas price for gas from the Elk Hills Naval Reserve. DRA's forecast showed no Elk Hills purchases and replaced those volumes with additional spot gas volumes at its forecast spot gas price. There is no dispute that for the last two years SoCal has bid and paid some premium to purchase Elk Hills gas. DRA has not included an Elk Hills premium because it does not believe it is prudent for SoCal to offer a premium. We agree with DRA. SoCal argues that ACAP gas cost forecasts should be based on the supplies the utility can reasonably be expected to purchase; and those costs are subject to after-the-fact disallowance in reasonableness reviews where positions such as those taken by DRA can be considered. If SoCal's argument is correct we would not need an ACAP hearing at all; just a reasonableness review, years after the event.[2]

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2 SoCal's 1988-1989 reasonableness review is still pending before the Commission.

An issue remains regarding the treatment of excess costs in Elk Hills purchases, should that situation occur. Essentially this same issue was argued in last year's SoCal ACAP, where the Commission deferred the issue of the reasonableness of SoCal's purchase to SoCal's reasonableness review proceeding. TURN supports a similar resolution of the Elk Hills issue in this case as long as consideration in the reasonableness review specifically includes the question of which customers should ultimately bear the excess costs of Elk Hills purchases in the event that such purchases are deemed reasonable at all. TURN points out that in D.90-01-015 we said:

> "In our opinion, Elk Hills purchases do not meet the definition of transition costs established in D.87-12-039 and should not receive transition cost treatment on that basis. We have not considered or decided, however, whether excess costs associated with Elk Hills purchases should for other reasons be allocated in a manner consistent with our treatment of transition costs. This issue should be addressed in a future proceeding <u>if and when SoCal requests such treatment</u>." (<u>Id.</u> at page 42.) (Emphasis added.)

TURN's concern is with the language which appears to permit only SoCal to request such treatment in a future proceeding, such as the appropriate reasonableness review. SoCal, in TURN's opinion, would have absolutely no incentive to offer such a proposal, because it would shift dollars from core to noncore, where the company is more at risk for cost recovery. TURN urges the Commission to state that any party may propose a different allocation of Elk Hills costs in the appropriate reasonableness review proceeding.

Edison agrees that the proper allocation of excess Elk Hills gas costs should be deferred to SoCal's reasonableness review proceeding. EOR Producers and Long Beach argue that only core customers should pay any Elk Hills costs as they are the ones who benefit.

We will follow D.90-01-015 to the extent that we will defer consideration of the reasonableness of Elk Hills purchase to the reasonableness hearing, but we accede to TURN's proposal that any party may propose an allocation of Elk Hills costs, whether those costs are reasonable or unreasonable, in the reasonableness hearing. SoCal should not be permitted to control the issue.

TURN recommends a "rates in effect" approach with respect to SoCal core supplies that are subject to price redetermination or recontracting for the upcoming ACAP period. TURN's proposal would mean that the forecast of price for these supplies would be equal to the average price SoCal is currently paying for these supplies. Given the long-term upward trend of inflation generally, and the general upward trend in energy and gas costs we foresee, TURN's position can only be expected to result in chronic accumulations of undercollected core gas costs in the Core Purchased Gas Account balancing account, a result which should be avoided.

There are essentially no differences between SoCal and DRA with respect to the forecast of fixed interstate gas supply costs (demand charges, reservation fees, direct bills, etc.). SoCal and DRA have agreed on the amount of all such items, plus the DRA forecast of El Paso direct bills of $63.4 million and DRA's PITCO price forecast.

4. <u>Account 191 and Refunds</u>

Account 191 is a holding account set up by the interstate pipeline companies under FERC's Uniform System of Accounts to record commodity gas costs which were incurred but undercollected from their customers in previous years. Currently, Transwestern's Account 191 costs total $33.5 million while El Paso's amount to $63.4 million. As of SoCal's last ACAP, (D.90-01-015), Account 191 costs had not yet been directly billed to the utilities. Since then SoCal has made Account 191 payments of $33.5 million to

Transwestern. To offset future Account 191 charges, the Commission in D.90-01-015 ordered that certain refunds received from Southland, Mid-La, and Chevron as a result of separate litigation be held in an interest-bearing account. These refunds were collected as part of a settlement relating to alleged interstate commerce violations and deferred tax charges. Account 191 charges are unrelated to these refunds. The resulting credit or charges, after offsetting the Account 191 costs with the referenced refunds, were to be allocated to all customers on an equal cents per therm basis. (D.90-01-015 at pp. 60-61.)

The treatment of the Account 191 costs and Southland/Mid-La/Chevron refunds set forth in D.90-01-015 were considered by the Commission to be offsetting and that all customers would bear the associated benefits/burdens on an equal cents per therm basis. Subsequently, however, the Commission issued D.90-04-021 in PG&E's 1990 ACAP in which it confirmed that the refunds were a transition cost while it specifically questioned whether Account 191 costs could likewise be properly considered a transition cost. (D.90-04-021 at pp. 29-32.) The Commission directed the immediate disbursement of the refunds to all customers and reserved its treatment of Account 191 costs until PG&E's next ACAP. With respect to the Southland/Chevron refunds currently held by SoCal in an interest-bearing account, the EOR Producers submit that the Commission should order such refunds, which they consider transition costs, to be disbursed to all of SoCal's customers on an equal cents per therm basis, consistent with the action it took in D.90-04-021.

CIG submits that it would be unreasonable to require noncore customers to subsidize SoCal's core gas purchase costs through transition cost treatment of Account 191 balances as those balances are nothing more than unrecovered purchased gas costs which were purchased from the pipelines for core customers. Not being incurred for the benefit of all ratepayers, CIG argues, they should not be recouped from all ratepayers. Long Beach makes much the same argument as the EOR Producers and CIG and adds that Public Utilities Commission (PU) Code § 453.5 mandates a pass-through to wholesale customers of the Chevron, etc. refund, without considering the Account 191 billings.

In D.90-01-015 we considered the disposition of Account 191 and the Chevron-Southland-Mid-La refunds. In all the refund matters DRA recommended that the refunds be held by SoCal as an offset to any Account 191 costs. DRA's recommendation was opposed and, based on the record, we adopted DRA's recommendations. (D.90-01-015 at pp. 60-61, Conclusions of Law 25 and 26 at p. 141.) The issue of refunds, having been decided in D.90-01-015, will not be relitigated in this proceeding. The PG&E D.90-04-021 dicta notwithstanding, for SoCal the issue is settled.

CIG argues that whatever net amount is left from the refunds after Account 191 offsets, that amount should be allocated to noncore customers. SoCal and DRA point out that there is no evidence of a net amount, there is no testimony on its allocation, and, therefore, the issue should be deferred to a later ACAP. We agree.

B. <u>System Capacity Availability</u>

SoCal and DRA agree on a forecast of system capacity available during the ACAP forecast period.

System Availability		MMcfd
California		197
POPCO		31
Pitas Point		42
El Paso		1,656
El Paso SSE		145
Transwestern		750
Interutility		150
	TOTAL	2,971

System capacity availability is a critical factor because rates cannot be based on forecast throughput in excess of SoCal's physical capacity to serve.

1. El Paso Availability Factor

SoCal and TURN differ on their forecasts of system capacity availability in two areas. First, TURN forecasts that El Paso can be utilized at 97% of its theoretical capacity, while SoCal forecasts that it can be utilized at only 96% of theoretical capacity. Utilization of capacity at less than theoretical maximum occurs because of unavoidable inefficiencies in El Paso's scheduling of dozens of shippers daily on its system. If a shipper does not deliver all the gas into El Paso's system that has been scheduled on a particular day, there will not be full utilization until the next day when performance can be corrected or another shipper scheduled. El Paso capacity can also go temporarily unused due to well freeze-ups in extremely cold weather.

In SoCal's last ACAP, the Commission adopted a forecast of 97%. Actual ability to use the El Paso system in 1989 was only 95.3% of theoretically-available capacity. Even if there were some improvement in El Paso's procedures during the 1990 ACAP period, SoCal's 96% factor is more realistic, and will be adopted.

2. PG&E Interutility Transportation Capacity

The second area of dispute with TURN is over the forecast of the amount of interutility transportation service to be available from PG&E to SoCal. Under the Commission's regulations, PG&E provides full service to its own customers and stores gas before making any of its capacity available to SoCal to bring in additional supplies from El Paso or Canada. The Commission must forecast what residual capacity PG&E will have, if any, to transport gas to SoCal.

SoCal and DRA both forecast an average daily utilization by SoCal of 150 MMcf of PG&E interutility transportation. SoCal's forecast was based upon the average daily utilization by SoCal over the three-year period 1987-1989 of 154 MMcf/d. SoCal noted additional factors, such as continued dry hydro conditions (increasing PG&E's own need for gas to generate electricity), PG&E storage plans, and Diablo Canyon nuclear fueling outages, that support a conclusion that 150 MMcf/d is at the upper range of a reasonable forecast. There is, however, a basis for adopting a lower forecast. For instance, in PG&E's latest ACAP D.90-04-021, the Commission adopted a forecast that PG&E would provide 120 MMcf/d to SoCal in a period that overlaps the 1990 ACAP forecast period by six months (October 31, 1990 to March 31, 1991).

By contrast, TURN's forecast that the likely amount of interutility service that PG&E could offer and SoCal could utilize in the ACAP forecast period is 235 MMcf/d, under average hydro conditions on PG&E's system. However, TURN recognized that it is not reasonable to expect that hydro conditions on the PG&E system could return to average until well into the SoCal 1990 ACAP forecast period. It simply does not rain much until well into the fall and winter in California, and it may take more than one year to replenish fully reservoirs depleted by a multi-year drought. Even TURN noted, by the time hydro conditions can improve for PG&E, thus lowering its gas demand and making more PG&E capacity available to SoCal, most of the curtailment forecast by SoCal for the ACAP forecast period will already have occurred.

PG&E supports a figure of 133 MMcf/d interutility transportation, which it claims is based on historical use. PG&E subtracted the qualities of gas which SoCal provided to PG&E to serve PG&E's EOR demand from the amounts SoCal received from PG&E. PG&E asserts that TURN's estimate is unrealistic as it ignores history as well as factors which restrict interutility service. SCUPP, Edison, and SDG&E all recommend less than 150 MMcf/d.

We will adopt a utilization of 150 MMcf/d. It was based on average daily utilization by SoCal over the immediate past three-year period. We are not persuaded that test year differences from prior years' conditions will significantly change the amount of gas delivered. There are always changes and differences; past trends and averages tend to smooth over variations and allow for change.

3. <u>SSE Capacity Availability</u>

The most significant issue regarding SoCal's system capacity availability is the question of when the SSE can be expected to be in service. SoCal and DRA estimate November 15, 1990.

The SSE involves the installation of additional pipeline capacity by SoCal from its southern interconnection with El Paso near Blythe on the California-Arizona border. The expansion also involves the installation of additional pipeline capacity and compression by El Paso east of the California-Arizona border. The nominal capacity of the planned facilities is 200 MMcf/d, but El Paso has not offered this additional capacity to SoCal on an entirely firm basis. SoCal has assumed available capacity to be 90% of nominal capacity, or 180 MMcf/d, once all facilities are installed. SoCal has also estimated that the expansion would increase SoCal's capacity by 100 MMcf/d after the new pipeline facilities are installed, but before El Paso's additional compression is installed. No parties have challenged SoCal's estimates of SSE capacity once facilities are installed; rather, the dispute is over the date at which the facilities can be expected to be in service.

Assumptions about the in-service date have a significant effect on rates for virtually all SoCal customers because of the effect of forecast levels of curtailment on cost allocation. SoCal and DRA both predict some P-5 curtailment, even with their assumption that the SSE will be available by November 15, 1990 (with compression by January 1, 1991). If the SSE were delayed beyond the time assumed by SoCal and DRA, their forecast of P-5 curtailment would be greater. The earlier the forecast availability of the SSE in this ACAP, the greater will be the forecast throughput to P-5 customers. Because UEG customers' fixed demand charges are established in the ACAP on the basis of forecast throughput, the earlier the forecast of SSE, the greater will be the ACAP-adopted UEG demand charges. Because SoCal's total non-gas costs are a fixed amount for the purposes of ACAP cost allocation (regardless of the in-service date of the SSE) higher UEG demand charges will mean offsetting lower rates for other customer classes. To the extent the forecast assumes a delay in the in-service date then all ratepayers, other than UEG, will pay higher rates.

Therefore, it is not surprising to find UEG customers arguing that the SSE will not come into service before September 31, 1991, or that it will come into service so late in the ACAP period that it will have no appreciable effect in alleviating UEG curtailment and increasing UEG throughput. UEG customers would prefer not to pay the higher demand charges they will receive if SoCal and DRA's forecast of the in-service date is adopted. Edison contends, and SoCal agrees, that the rate effect on Edison is $9 million if SoCal's forecast is adopted but the facilities do not actually go into service at any time during the ACAP. However, SoCal emphasizes that all of the increase in UEG demand charges would go to reduce other customers' rates.

Both SoCal and DRA forecast that the planned SSE pipeline facilities will be in place on November 15, 1990, and El Paso's compression facilities will be installed by January 1, 1991. SoCal testified that this project has the very highest priority with SoCal. SoCal maintains that its forecast is realistically achievable. El Paso's facilities depend on the date FERC issues a certificate.

SoCal asserts that its forecast has financial significance for SoCal as well as for its customers. If rates are based on SoCal's forecast but the project is delayed, then SoCal will fail to achieve the forecast throughput and will receive less revenues from UEG volumetric transmission rates than forecast in the ACAP; thus, SoCal's earnings will suffer. SoCal states it has no financial incentive (indeed, it has a disincentive) to forecast an unrealistically early in-service date.

Edison points out that the Southern System capacity will increase SoCal's system reliability and reduce SoCal's need to curtail noncore customers, resulting in higher throughput for such customers. The higher throughput will, in turn, increase the noncore revenue requirement as well as noncore rates. For this reason, Edison proposes that rates reflecting the effect of the expansion not be implemented until the expansion is actually operable and capable of providing the higher level of service for which noncore customers will be required to pay. Phased-in rates will allow SoCal to match the recovery of the cost effect of the expansion with the benefits that it provides.

Edison proposes that the effects of the expansion be recovered through phased rates. Under this proposal, the initial phase of rates would be implemented at the start of the ACAP period and would be determined assuming that the expansion will not be in service during the entire period. The second phase of rates would be calculated to reflect the assumption that the expansion is fully in service (both interstate and intrastate) during the entire period, but would not be implemented until the expansion in-service date. Under this calculation, the second phase rates will thus reflect the cost effect of the expansion no matter when the in-service date occurs within the ACAP period. Edison argues that its proposal for phased rate treatment guarantees that all SoCal ratepayers, as well as its shareholders, are not disadvantaged by the uncertainty associated with forecasting the in-service date of the expansion. SCUPP and EOR Producers support Edison, with the EOR Producers adding the additional complaint that SoCal has reallocated $1.5 million of costs of the Southern System to the transmission cost category, which costs are paid by the noncore customers. TURN supports SoCal's estimate of the in-service date.

In our opinion the evidence supports SoCal's in-service date estimate. SoCal is the party most interested in having the expansion running on time. Not only does SoCal lose by delay, but also it has no incentive to estimate an overly optimistic online date. Edison's proposal would have the core customers pay higher rates up to the date the expansion goes into service as if the distribution projects which SoCal deferred from its capital budget in order to give priority to the expansion were actually built and providing service.

As TURN points out:

> "Edison's proposal is nothing more than another 'beggar thy neighbor' cost allocation ploy. There is nothing equitable about charging one group of customers (the core) for the costs of facilities that may never be built (the deferred distribution projects) just to spare another group of customers (the UEGs) from the costs of a facility (the southern expansion) that has been temporarily delayed. If anything, this proposal would give SoCal a financial incentive to delay the expansion so as to prevent the reallocation of costs to noncore customers who are not subject to balancing account protection! Regardless of the surface appeal that it may have at first glance, the Edison proposal is really nothing more than a self-serving allocation scheme fraught with perverse incentives. Core customers should not be forced to pay for facilities that don't exist just because the expansion might be delayed."

There is no credible evidence that the Southern System will not be constructed on time. The evidence to the contrary is persuasive. We take official notice of D.90-10-035 wherein we specifically authorized the reallocation of dollars from distribution to transmission to fund the SSE. We will adopt the SoCal estimates.

IV. Demand Forecast

A. Comparison of Demand Forecasts

Gas throughput is a measure of the total demand for natural gas that can be supplied during the ACAP period. It reflects forecast gas demand, forecast gas supply, and any curtailments for gas during the ACAP period as a result of gas supply or system capacity constraints. Throughput estimates are a key factor used in allocating costs among the various classes of customers and thus have a direct effect on rates. Costs are allocated to the core and noncore classes depending upon the forecasted throughput. The utility is at risk for noncore costs while core costs are given balancing account treatment.

DRA and SoCal developed econometric models to forecast throughput to various classes of service. Generally, the models forecast demand as a function of weather, the price of natural gas, the price of substitute fuels, and economic activity in the SoCal service area. The resulting forecasts are then disaggregated into rate schedules and priorities. Although the DRA model differed from the SoCal model the resulting core estimates showed a difference of less than 1%. However, DRA's noncore industrial forecast exceeded SoCal's by 13%, mostly as a result of the difference in assumptions of gas and oil prices.

DEMAND FORECAST
(MMDth)

	DRA	SoCal
Residential	279.8	285.2
Commercial Core	76.3	74.1
Commercial Noncore	17.4	17.1
Industrial Core	35.6	35.6
Industrial Noncore	76.8	70.9
Retail UEG	197.6	204.9
Regular Cogeneration	70.5	70.5
EOR Cogeneration	128.1	123.7
EOR Streamflood	48.6	56.3
Company Use	7.2	7.2
Unaccounted For	11.4	11.5
Long Beach - Wholesale	29.1	29.0
San Diego - Wholesale	113.7	110.6
Subtotal	1,092.1	1,096.7
Exchange	32.0	32.0
Interutility Transport	7.5	7.5
Total Demand	1,131.66	1,136.2

The primary area of dispute is in the industrial noncore market segment. In this market DRA forecasts that market demand for gas will be 5.9 MMDth greater than SoCal's forecast. This difference is quite significant. Accurate predictions of gas demand are crucial to a fair allocation of costs and to providing the utility with a fair opportunity to earn its authorized rate of return. If an unrealistically high forecast of gas demand for a particular class of customers is adopted, that customer class will be allocated an inordinately large share of the utility's revenue requirements and rates would be designed so that the allocated revenue requirement would be recovered only at the adopted level of demand. If the actual demand level is anything less, the utility will underrecover its revenue requirements.

Pursuant to the directives of the Commission in its decision in SoCal's 1989 ACAP (D.90-01-015), SoCal used linear demand forecasting models in this proceeding. DRA also used linear models and the differences between the approaches taken by SoCal and DRA are far smaller than existed in SoCal's 1989 ACAP. There is however, a significant difference in modeling technique that explains a large part of the disparity in SoCal's and DRA's forecasts of noncore industrial demand.

The DRA model produces a price elasticity which is constant regardless of the relative price of gas to oil. The SoCal model allows the elasticity to change as the gas/oil price changes. The DRA model assumes the same demand response regardless of the gas to oil price ratio; the SoCal model is more flexible. In the instance where gas prices are lower than oil and users have already switched from oil to gas, under the DRA model, a further reduction in gas prices would show increased gas usage; under the SoCal model the increased usage would be much less.

In addition to the gas/oil price ratio, another important factor in predicting gas demand in the noncore industrial market is the level of industrial output. Both the SoCal and DRA models use forecasts of employment levels as a proxy for the level of industrial output. SoCal's employment forecasts are based on DRI's employment projections which have been adjusted to reflect employment levels in the SoCal service territory. DRA, on the other hand, uses the March 1990 University of California at Los Angeles, "Business Forecast of the California Economy." As the name implies, the forecast relied upon by DRA presents a forecast for statewide employment levels. Because SoCal's forecast relates to employment conditions in the SoCal service area, it is a plus consideration, although minor.

More to the point is DRA's forecast of lower industrial employment, but higher use of gas in the industrial sector. This is difficult to reconcile, especially when we expect little fuel switching from oil to gas during the ACAP period. Finally, the use of different gas price forecasts in the econometric models explains much of the discrepancy between the forecasts. As we have adopted the SoCal gas price forecast, we believe that the SoCal demand forecast appears reasonable and should be adopted, except for SDG&E, which will be discussed in SDG&E's section of this opinion.

Noneconometric throughput forecasts are used to forecast demand for UEG, EOR, and wholesale UEG classes. Again, DRA and SoCal have arrived at similar forecasts for most classes using different approaches. Again, the differences are due to the fuel price inputs. DRA expects gas prices to be lower and LSWR prices higher than SoCal's forecasts. SoCal is forecasting economic fuel switching for SDG&E and EOR steamflood customers. DRA does not expect any economic fuel switching to occur. Regardless of individual category differences, the total throughput forecasts of DRA and SoCal differ by less than 1%. But because we do not expect economic fuel switching for SDG&E and EOR customers, we will adopt SoCal's noneconomic throughput forecast, modified by eliminating economic fuel switching. Based upon our demand forecast, P-5 average year curtailments are expected to reach 35,521.4 MDth.

B. The Demand Forecast Dispute with SCUPP

There is a dispute between SoCal and SCUPP over the gas demand forecast for the cities of Glendale, Burbank, and Pasadena. These municipalities are all members of SCUPP and utilize gas as a fuel for their municipally owned UEG systems. SoCal's forecast of the gas demand for these cities was developed using SERASYM, the Sierra Energy and Risk Assessment Inc. production cost simulation model. The SERASYM model requires as an input the forecast electrical demand for each UEG customer and then utilizes various resources to meet that electrical demand. A product of this model is a determination of the amount of gas that will be used by the UEG to generate electricity.

Although the cities are separate entities, SoCal combined them for purposes of forecasting their aggregate gas demand. SCUPP challenged this approach and advocates that separate SERASYM models should be developed for each of the three cities. SoCal generally agrees with this proposal, but did not have access to a separate forecast of electrical demand for each of these cities. SoCal sent a data request to SCUPP requesting such information after an informal request proved futile. As of the eve of the testimony of SCUPP's witness no response to SoCal's data requests had been provided.

SCUPP asserts that the Commission should adopt SCUPP's revised demand forecast because it is more accurate and reliable than SoCal's demand forecast for retail UEG customers. SCUPP states that its revised demand forecast is based upon the use of the same production costing model (SERASYM) that was used by SoCal, but is more accurate and reliable in several respects. As more particularly described by the SCUPP witness the input data used for the SCUPP members in SoCal's SERASYM model runs made certain assumptions that were inconsistent with actual and historical experience, as well as the individual customers' planning parameters. The inconsistencies and errors in SoCal's methodology were corrected in the demand forecast sponsored by SCUPP by changing the input data to better reflect actual planning criteria of SCUPP members with respect to their resources. These revisions, in SCUPP's opinion, produced a more accurate SERASYM model on which to project SCUPP's demand requirements than the model used by SoCal.

For instance, in regard to the Intermountain Generating Station (IGS) forced outage rate and scheduled maintenance, SCUPP contends that SoCal's SERASYM runs incorrectly assumed a 15% forced outage rate for IGS and a scheduled maintenance of eight weeks rather than the more accurate seven weeks. Also, SoCal predicted a forced outage rate significantly greater than recent historical experience. As a consequence, the revised input assumptions result in equivalent availability of IGS of about 92% in contrast to SoCal's assumption of "about 70 percent" availability during the ACAP period. Ninety-two percent is consistent with the way in which the plant has operated, according to SCUPP.

SCUPP presented evidence to show that SoCal's forecasts were inaccurate as to LADWP's Mohave Units 1 and 2 and Montana Power resources, as well as the "must run" units of LADWP, Burbank, Glendale, and Pasadena. Finally, SCUPP introduced evidence to show that SoCal's treatment of Burbank, Glendale, and Pasadena as if their resources were dispatched jointly, was not the way the systems operate. Each city has its own entitlements to IGS, which are dispatched individually, each has its own generating resources which are dispatched individually, and each has additional unique resources. Accordingly, the results of the forecast for the individual cities can be skewed when the three cities are modeled together.

SCUPP believes that the revised demand forecasts for the three cities give a more accurate projection of actual gas demand than the demand forecasts of SoCal and are the best available interim solution under the circumstances. The SCUPP forecast for the three cities is as follows:

	Forecasted Demand in Units (MDth)
Burbank	2,878
Glendale	2,530
Pasadena	3,315
Total	8,723
SoCal Combined Forecast	9,520

SCUPP contends that the Commission should adopt its forecast and, in addition, to avoid the modeling problem for the three cities in future ACAPs, the Commission should direct that separate models be run for each city commencing with the 1991 ACAP.

DRA did not perform independent production cost model runs for each of the three cities. Instead, DRA had SoCal run the SERASYM model using DRA's forecasting fuel prices and economy energy prices. The results of the SERASYM run using DRA's forecasted prices resulted in the following demand volumes for the cities.

Burbank	2,760 MDth
Glendale	2,160
Pasadena	4,600
	9,520 MDth

C. Discussion

DRA and SoCal, using the information available to them at the time of their computer runs arrived at the same demand volumes. SCUPP, two weeks prior to the hearing, presented written testimony based on purportedly more precise information. SCUPP is not a new participant before this Commission, nor are the entities it represents. In fact, a comparable presentation was made in SoCal's last ACAP. (See D.90-01-015 at pp. 28-30). What concerns us is that SCUPP saw no necessity to present historical data and other pertinent information to SoCal and DRA in time to permit adequate study. This kind of information should have been volunteered by SCUPP before SoCal had even filed its application, and certainly should have been delivered in response to SoCal's data requests. Our being presented with the results of two sets of computer runs and having to make a decision without the benefit of DRA review of the input data and without the results of meetings between the experts of all interested parties, leaves us with the feeling of deciding on an inadequate record. But we must decide and since the inadequacy was caused by SCUPP we have no hesitancy in adopting SoCal's estimate. In order to have a complete record for SoCal's next ACAP, SCUPP should present the data SoCal requests by December 1, 1990 at the latest.

D. The Discount Adjustment Methodology

The Commission has authorized gas utilities to discount noncore rates in order to increase the sales volume over which the utilities fixed costs are spread. The discount adjustment is a mechanism used to adjust noncore revenue estimates to reflect the amount of incremental, or additional, revenue a utility can earn from noncore industrial sales through discounting. The adjustment is expressed as a percentage reduction in forecast industrial noncore demand. It is set at the appropriate percentage so that forecast sales (including sales achieved through discounting) multiplied by the ceiling rate equals total forecast revenue.

The discount factor is important. Adopting more discounting than what will actually occur amounts to writing a bonus check to shareholders and adopting less comes out of the shareholders' pockets. If the utility actually discounts more than the ACAP forecasts (or if noncore revenues are below the forecast for any other reasons), the utility stands to earn less than its allowed return. If the utility actually discounts less, the utility earns more. In the last analysis, however, it is the ability of the utility at the negotiating table with potential customers which will determine the revenue that will be obtained from discounting. Unfortunately, given the nature of forecasts and the fact that noncore revenue allocation is at risk for the utility, the utility has a strong incentive to denigrate its own ability to negotiate and all other parties have an equal and opposite incentive to impute skillful negotiating ability to the utility. For instance, if we assume maximum effective negotiation then the amount allocated to the noncore portfolio will be higher and the amount allocated to the core portfolio will be lower; if we assume a less effective negotiating ability then the amount allocated to the noncore will be lower and the amount allocated to the core will higher. But, should we assume a less effective negotiating ability and in fact it turns out that the utility can negotiate much more favorably the utility will obtain windfall profits.

The Commission Advisory and Compliance Division (CACD), working under direction from the Commission, convened a workshop in May 1990 for the purpose of developing a uniform discount adjustment (DA) methodology for use in ACAP proceedings. The CACD

DA methodology was distributed June 15, 1990 and became an exhibit in this proceeding. The CACD recommendation is a modification of the DA methodology proposed by SoCal and supported by TURN and DRA. CACD recommends that all gas utilities be required to include the CACD base case DA methodology in all ACAP filings. The CACD report is Appendix B of this decision.

The methodology used by DRA is similar to that used by SoCal in its application, but differs in certain key respects. Under both the DRA and SoCal methodologies, the volumes which can be achieved through discounting the transportation rate are estimated based on second-degree price discrimination below a default rate for P2B and Other Industrial (P3 and P4) customers. However, SoCal differs from DRA in some of the input assumptions used in the discount adjustment calculation. DRA's methodology is consistent with the CACD report, while SoCal's is not.

The first area of discrepancy between the SoCal discount calculation and the CACD report is in the floor rate used in the calculation. The CACD report states that the floor rate is defined as "the lowest rate at which gas is expected to be sold during the forecast period, but should not drop below the expected average UEG rate during periods of capacity curtailment." SoCal did not use this floor rate; DRA did.

The SoCal methodology also deviates from CACD's recommended methodology with regard to the price intervals at which demand is calculated. Under the CACD methodology, demand price intervals from the floor rate to the default rate are to be calculated. Each price change is to be in successive 1 cent/therm steps. DRA used the one cent per therm steps in its calculation. SoCal, in contrast, used 2.5 cent increments. SoCal argued that it believes that 2.5 cent increments provide a better representation of the incremental revenue which can be achieved through the negotiating process, but SoCal agreed that use of smaller increments in the model results in higher assigned revenues to the noncore. The effect of SoCal's use of a larger increment than was recommended by CACD is to decrease risk to SoCal by reducing the amount of revenue to be assigned to the noncore. The smaller the increment used, the greater the revenue assigned to the noncore, although the differences resulting from use of the 2.5 cent increment instead of a 1 cent increment is slight. The CACD report provides for 1 cent intervals. DRA believes that regardless of the magnitude of the effect of using larger increments (there is no evidence on the record of the effect), the Commission should adopt the 1 cent interval methodology in this proceeding because it is not result-oriented, and was found by CACD to be the superior method.

DRA and SoCal differ in the elasticity factor assumed in the calculation. SoCal assumes a lower elasticity than DRA. This is significant because a lower elasticity implies that quantity is less responsive to price changes than at a higher elasticity. Because of this fact, for a given percentage decrease in price (in this case this would mean a price discount), a greater elasticity produces a greater percentage increase in quantity than a lower elasticity produces. The result, then, of SoCal's use of a lower elasticity than DRA is to forecast less revenues from price discounting.

There is no doubt that SoCal has made assumptions in its discount adjustment calculations that conflict with the methodology recommended by CACD in its report to the Commission. DRA, on the other hand, used a methodology that is consistent with the CACD report. We will adopt DRA's methodology in order to promote consistency in the discount adjustment methodology used in ACAPs. And because we have adopted a relatively high spot gas forecast, we believe that price elasticity will be a significant factor in generating sales based on discounting. The difference in incremental revenues between the DRA/CACD method and SoCal's methods is about $500,000 more sales under DRA/CACD.

V. Revenue Requirements and Cost Allocation

A. Conservation Cost Adjustment Account

Conservation related litigation costs amounting to $7.2 million are at issue for this account. The source of the issue is a perceived inconsistency between SoCal's last ACAP and last general rate case decisions. D.90-01-015, SoCal's last ACAP proceeding, found that conservation related litigation costs should not be recovered through the Conservation Cost Adjustment Account (CCA) balancing account. However, D.90-01-016, SoCal's last general rate case, issued on the same day as the ACAP decision, found that the reasonableness of conservation related litigation expenses should be determined in SoCal's next CCA proceeding. The core/noncore split of the disputed amount is $5.9 million and $1.3 million respectively.

SoCal asserts that the conservation related litigation costs should be retained in the CCA balancing account pending final resolution in the next CCA proceeding. DRA asserts that the conservation related litigation costs should be entirely removed from the CCA balancing account.

We agree with DRA. SoCal has misinterpreted our prior decisions. In D.90-01-015 we considered the matter of litigation and settlement costs in great detail and concluded that those costs were not to be included in the CCA balancing account. (Conclusion of Law 27, p. 141.) Our reasoning is set forth on pp. 64-66 of D.90-01-015, to the effect that to give balancing account treatment to litigation and settlement costs eliminates "any economic stake utilities have in claims and litigation." (P. 64.) Our reference to the CCA balancing account in D.90-01-<u>016</u> did not contradict D.90-01-<u>015</u>. In <u>016</u> we considered our decision in <u>015</u> and said that "SoCalGas may present testimony on the reasonableness of its conservation related litigation expenses...in its next CCA proceeding." (D.90-01-016 at p. 66.) The two decision are consistent. Litigation and settlement costs are recovered on a forecast basis through the allowance for administrative and general (A&G) expenses included in base rates. (D.90-01-015 at p. 65.) The allowance for A&G expenses is set on a forecast basis in a general rate case. The forecast, itself, is based on, among other things, reasonable costs incurred in prior years. Our discussion in 016 was merely to the effect that the reasonableness of litigation and settlement costs in prior years should be determined in a CCA proceeding, but only for the purpose of forecasting future litigation and settlement costs in the next general rate case, not for the purpose of granting SoCal additional revenue to cover those costs. To accede to SoCal's argument would permit a double recovery of those costs: once in A&G expenses and once in the balancing account.

B. Low Income Residential Assistance Issues

The Low Income Residential Assistance (LIRA) program is subject to a future reasonableness review whereby inaccuracies in the forecast can be corrected. The DRA projection of LIRA expenses of $21,836,000 for the forecast period is based on the total discount to residential customers, the A&G expenses associated with the program, and the LIRA balancing account which reflects over or undercollections from the previous period.

DRA's LIRA volumetric forecast for the ACAP period is 21,880.2 MDth. This contrasts with SoCal's forecast of 22,322.27 MDth. Both DRA and SoCal used the same methodology for computing the LIRA volumes, with the exception of the residential volume forecasts. To develop the annual LIRA volumes, the total annual residential sales forecast is multiplied by the ratio of the annual LIRA customers to the total annual residential customers. DRA accepts SoCal's customer forecast. SoCal estimates the participation to be 40% of the 1,000,000 eligible customers.

DRA made four recommendations for the LIRA program:

1. The development of curriculum item in the A&G account should be disallowed. This is a one time cost that was incurred at the onset of the LIRA program. SoCal agrees with the recommendation, which results in a $51,000 reduction in SoCal's forecast of LIRA administrative costs.

2. Training costs should be reduced by 50% as the program is seasoned and less time will be needed for retraining employees.

3. The costs of processing applications should be reduced by 25% as a result of increased speed and expertise in processing. SoCal acknowledged that overtime processing should become more efficient, but did not forecast any reduction for this ACAP period.

4. Additional correspondence costs should be based on mailing 15,000 incomplete applications at a cost of 25 cents postage per application.

DRA recommends a total of $716,425 be allocated for LIRA administrative costs. This compares to SoCal's recommendation of $939,000. DRA's forecast of the LIRA A&G costs does not address the issue of the reasonableness of the costs. SoCal forecasted the LIRA balancing account to be $1,272,000. DRA accepts SoCal's estimate for ratemaking purposes in this ACAP. The LIRA balancing account is, however, subject to reasonableness review as directed in D.89-09-044.

DRA's LIRA program is reasonable and its cost estimates will be adopted.

C. Women and Minority-owned Business Enterprises Costs

A number of parties have challenged SoCal's proposed allocation of costs incurred in 1989 for the Commission authorized clearinghouse for the Women and Minority-owned Business Enterprises

(WMBE) program. Because the cost of the clearinghouse was not already included in rates, the Commission allowed SoCal to record its 1989 cost in an account for later recovery. The total amount to be spread among SoCal's customers is $258,000 (including franchise fees and uncollectible costs (F&U)).

SoCal has proposed to allocate these past clearinghouse costs to all of its customers on an equal cents per therm basis. It argues that the WMBE program is intended to achieve general social goals and cannot be said to be a benefit to only one particular customer class or another. Second, SoCal incurs WMBE costs in order to achieve purchasing goals for all goods and services it purchases, for all customers.

DRA accepts SoCal's estimate of WMBE costs subject to reasonableness review, but argues that EOR customers and SDG&E should be exempt from paying their share of these costs because parties with their own WMBE programs will suffer a double burden. Long Beach argues that it should be exempt because there is no proof that WMBE costs are related to transmission level service or wholesale service. SoCal does not believe that any of its customers should be excused from an allocation of WMBE costs just because they may participate in the clearinghouse for their own purchasing activities (SDG&E), or have their own independent affirmative action purchasing programs (Long Beach, LADWP). SoCal provides gas transmission service for these customers that they do not have to provide for themselves, thus avoiding the affirmative action purchasing costs associated with providing the service. In regard to SDG&E, SoCal asserts that the WMBE program is fundamentally different from the LIRA program, where SDG&E is exempt from the LIRA surcharge. SoCal's LIRA program costs are associated with serving only SoCal's retail residential customers, so SDG&E should not be allocated LIRA costs. However, SoCal's WMBE costs are associated with service SoCal provides to SDG&E, so SDG&E should pay its share.

We agree with SoCal for the reasons it gives. To accede to DRA's argument would cause us to exempt every utility, city, county, and any other organization that has its own WMBE program and buys gas from SoCal.

D. Storage Banking Revenues

The Pilot Storage Banking Program has been extended through the ACAP forecast period by D.90-10-038. As a consequence, storage revenues are to be treated as credits to noncore customers on a recorded basis rather than on a forecast basis. Therefore, SoCal's actual storage banking revenues of $1,621,600 should be credited to noncore customers.

E. Allocation of Transmission Cost to SDG&E - Line 6900

SoCal has allocated to SDG&E 100% of the cost of new transmission line 6900, which runs from SoCal's interconnection with SDG&E at Rainbow part of the way north toward SDG&E's Moreno compressor station in SoCal's service territory. Line 6900 partially loops existing SoCal transmission lines 1027 and 1028. SoCal constructed line 6900 at SDG&E's request in order to provide capacity to serve SDG&E's growing load.

Although the vast bulk of gas (96.3%) moving through lines 1027 and 1028 is delivered to SDG&E, SoCal has taps on those lines, and about 3.7% of the volumes on those lines flow to SoCal retail customers. Therefore, SoCal has allocated 96.3% of its cost directly to SDG&E, and has allocated the remaining 3.7% to SoCal's customers. SDG&E proposes that the cost of line 6900 be allocated on the same 96.3%/3.7% split. Because line 6900 has no taps that allow SoCal to serve its retail customers from it and because construction of line 6900 was at SDG&E's request, SoCal's 100% allocation of line 6900 to SDG&E is reasonable and adopted.

F. Carrying Cost of Storage Inventory Credit

The parties disagree about the amount of credit to be given to wholesale customers with respect to the carrying cost of storage inventory (CCSI). D.90-01-15 at pp. 86-87 provided that the amount of CCSI allocated to wholesale customers in that decision would be subject to refund to those customers to the extent that they stored their own gas in SoCal's storage fields, thus relieving SoCal of the need to store gas it owns to protect service to wholesale customers. SoCal estimates the total credit at $600,000.

SoCal contends that the credit can only be applied for gas stored by the wholesale customers from and after the date of D.90-01-015. Rates in effect for wholesale customers before that date were in no way subject to refund for CCSI cost allocations. Second, only the costs that SoCal avoided are relevant to the credit. The costs allocated in the first place were SoCal's costs. The carrying costs incurred by wholesale customers to put their own gas in storage should be of no consequence to SoCal or its customers.

DRA's analysis of the amount of carrying costs credit to which SDG&E and Long Beach are entitled concluded that SDG&E is entitled to a credit of $854,000 and Long Beach is entitled to a credit of $105,000 for their own carrying costs of gas in storage as an offset to charges for CCSI allocated by SoCal. Both SDG&E and Long Beach agree with DRA's recommendation, which is based on its interpretation of D.90-01-015 that the credit is computed on the amount of gas actually stored from May 1, 1988 through April 30, 1990. We will adopt DRA's recommendation. SoCal agrees with DRA's recommendation that the cost of the credit be spread on the basis of cold year peak season to all customers except EOR.

G. Allocation of New Accounts/Costs

1. Mutual Assistance Agreement Gas

DRA and SoCal are in agreement on the methodology used to allocate the mutual assistance agreement (MAA) gas costs. The MAA gas costs resulted from gas sold at a loss to customers in the period from December 25, 1987 to January 17, 1988. In D.90-02-044, the Commission found that the MAA gas did not benefit P1A, P2A, and P5 customers and that the cost of MAA gas should be allocated to those groups who benefited from the purchase of the gas. (D.90-02-044 at p. 38.) The Commission stated in Finding of Fact 31 in that same decision that SoCal resold the gas to its P2B-P4 customers at a loss of $3,777,003. Therefore, DRA proposes that the MAA costs should be allocated on the basis of average year throughput to P2B-P4 customers. Both DRA and SoCal made this allocation.

2. Excess Commodity Purchase Gas

Excess commodity purchase gas is gas that was purchased to avoid curtailment, and was sold to SoCal customers at a loss of $2,994,000. In the recent SoCal reasonableness review decision, D.90-02-044, the Commission did not explicitly state whether the loss on the sale of this gas was reasonable or unreasonable. We did state, however, that the cost associated with the loss should be allocated in this ACAP proceeding (D.90-02-044 at p. 9), but we did not specify an allocation method. Conclusion of Law 9 of D.90-02-044 states that "SoCalGas incurred transition losses of $2,993,783 in 1986-87 on account of gas purchased for interruptible customers."

In its application SoCal allocated the excess commodity cost to all customers since it considered the excess commodity cost to be an ordinary transition cost. DRA disagrees with this characterization. TURN supports DRA. DRA believes that the loss associated with this gas cannot be treated as a traditional transition cost because it does not fit the criteria for transition costs established by the Commission in D.87-12-039, that it "was initiated for the benefit of all ratepayers." (D.87-12-039 at p. 15.) In this instance, the benefits of the excess commodity purchase gas were enjoyed exclusively by the UEG customers. While D.90-02-044 in Conclusion of Law 9 does refer to the excess commodity costs as a transition cost, it also states that this cost was incurred for interruptible customers, not all customers. Thus, DRA says, it is clear that the Commission in D.90-02-044 did not use the term "transition cost" in the traditional sense. Because the Commission did not apply the strict definition of transition cost to the excess commodity losses, and since the losses do not meet the transition cost criteria spelled out in D.87-12-039, DRA believes that the cost should be treated as a special case of transition cost.

Specifically, DRA believes that the excess commodity costs should be allocated to UEG customers who benefited from the excess commodity purchases. The loss of $2,993,783 was derived in D.90-02-044 by taking the difference between the price SoCal paid for the gas and the price at which it was sold to the UEG and wholesale customers. Only UEG customers were charged for the gas at a price below cost. In other words, the loss on sale resulted only from the sale of gas to UEGs. DRA reasons that it would be inequitable to require core customers to share in the excess commodity purchase costs, from which they did not benefit; the most equitable allocation of the excess commodity costs would be to allocate them to UEG customers, who benefited from the gas. Should the Commission feel that limiting allocation to only the UEGs is inappropriate, then DRA recommends that the Commission allocate the costs to all noncore customers. This alternative recommendation is consistent with Conclusion of Law 9 in D.90-02-044 which makes reference to purchase of the gas for "interruptible customers." In no event should any of these costs be allocated to the core, which did not benefit from this gas in any way.

SoCal argues that the $2,994,000 is a transition cost and, as such, should be allocated to all customer classes. SDG&E and Long Beach argue that only the retail UEG customers should pay; SDG&E and Long Beach did not cause the undercollection to occur and should not be allocated any of the shortfall. SCUPP argues that these costs should not be allocated to UEG customers since, at the time in question, spot gas was used to serve UEG P-5 load and spot gas was cheaper. In the alternative, SCUPP argues that these costs should be allocated to all customers. EOR Producers and Edison make much the same argument.

In our opinion the evidence supports the position of DRA and TURN except as it applies to SDG&E and Long Beach. Unfortunately, the language of D.90-02-044 is ambiguous. While it said that the excess commodity purchase gas was a transition cost (and, therefore, subject to allocation to all customers) it also said it was purchased "for interruptible customers" (and, therefore, should be allocated to interruptible customers). Not unnaturally all the interruptible classes support the SoCal recommendation to spread the cost to all classes. As the issue was left open for disposition in this proceeding we have reviewed the Commission decisions which are apposite and believe the better view is to hold that (1) transition costs are those that were incurred to benefit all ratepayers (D.87-12-039 at p. 15) and (2) the costs in question were found to have been incurred to benefit interruptible customers (Conclusion of Law 9 in D.90-02-044), leading to (3) the commodity purchase gas costs are not transition costs and therefore should not be collected from all ratepayers. As the noncore customer was the one who benefited, the noncore customer should pay, excluding SDG&E and Long Beach who did not benefit and who paid full price for their gas.

H. Balancing Accounts

SoCal proposes to close certain balancing accounts which are near being fully amortized. These are the Noncore Transition Cost Account (NTCA) and the Noncore Fixed Cost Margin Shortfall Account (NFC Margin Shortfall). The remaining balances in these accounts SoCal proposes to include in the Noncore Implementation Account (NIA). Although no party is opposed to the idea of closing unnecessary balancing accounts, SDG&E objected to these specific proposals on the basis that while it agrees that it does not participate in the NIA, it is entitled to an allocation of any overcollections in the NTCA and/or the NFC Margin Shortfall account. Long Beach supports SDG&E.

SoCal agrees that wholesale customers should receive their allocated shares of any over (or under) collections in these accounts before they are rolled into the NIA to the extent they participated in accumulation of the respective balances. That adjustment can be calculated at the time of the final decision.

We agree with SoCal and will authorize the closing of the NTCA and NFC Margin Shortfall accounts, with a transfer of the remaining balances to the NIA.

VI. Rate Design

A. Surcharges for Account Balances

SoCal requests a full 12-month opportunity to amortize in rates balances accrued in four tracking accounts during the period before SoCal's 1989 ACAP period. The accounts track differences between forecast and recorded costs of certain kinds, with a net undercollection. The 1989 ACAP decision, D.90-01-015, fixed rates that provided for amortization of the net balances in rates over forecast 12-month volumes. However, D.90-01-015 was not issued until well after the scheduled revision date of October 1, 1989. If the present ACAP goes into effect less than 12 months after rates established by D.90-01-015 became effective SoCal will not have had a full opportunity to recover the accrued balance over a 12-month period. SoCal, therefore, proposes to institute a surcharge to be in effect from the date of the decision in this case until January 14, 1991, when exactly 12 months will have expired since rates adopted in D.90-01-015 became effective. The surcharge is in addition to other rates. SDG&E opposes this request on the ground that the tracking account provides an opportunity to recover costs, not to guarantee that recovery. We acknowledge SDG&E's characterization, but believe it is misapplied in this instance. By extending the time to collect the account we are merely giving SoCal a full year, which was our original intent. It will be granted.

B. <u>Volumes Included in UEG Tier I</u>

The calculation of the volume of throughput that should be billed at the UEG Tier I volumetric rate, as opposed to the UEG Tier II volumetric rate, is disputed. The two-tiered UEG rate structure has existed for a number of years. In D.86-08-082, the Commission set the UEG Tier I volume at 18.5% of forecast UEG requirements in order to cover estimated requirements of start-up, flame stabilization, gas turbine, and smog episode day gas. D.87-12-039 at p. 99 described the UEG Tier I volume as being 18.5% of "throughput." That decision used the word "throughput" to mean sales plus transportation-only service; it did not need to distinguish between throughput and demand because the decision did not forecast any curtailment. The situation has now changed. Both SoCal and DRA are forecasting some UEG curtailment during the ACAP period.

SoCal and DRA contend that UEG Tier I volumes should be 18.5% of forecast UEG demand; Edison also recommends that the Commission adopt SoCal's proposal of 18.5% of forecast UEG demand. SoCal argues that the 18.5% allowance was intended to cover certain UEG end users, that requirements for these end users do not vary with curtailment, and that calculating UEG Tier I volumes based on the level of service after curtailment entails mathematical complexities and circularities that are difficult or impossible to resolve. DRA agrees with SoCal that in this instance "throughput" should be equated to "demand."

We will adopt the position of SoCal and DRA. This will insure that UEG Tier I load will in fact be assigned priority 3, and thus receive greater protection from curtailment than might otherwise occur.

C. UEG Rate Design

Two disputed issues involve UEG rate design. The first involves the allocation of the cost of SoCal's return on equity between the UEG demand charge and the UEG volumetric rate. In D.87-12-039, the Commission stated that 25% of SoCal's return on equity for UEG service should be included in the UEG volumetric rate; the remainder of the rate of return should be included in the UEG demand charge. The issue in this case is whether "return on equity" includes or excludes return on preferred stock. SoCal submits that for ratemaking purposes preferred stock is more akin to debt than to equity. For purposes of rate design, therefore, preferred stock in the capital structure ought to be treated like debt, not common equity.

DRA asserts that in last year's SoCal ACAP decision (D.90-01-015) and in the last PG&E ACAP decision (D.90-04-021), the return on preferred equity was lumped in with return on common equity and transferred, along with taxes, to volumetric rates. DRA believes that preferred equity was included with ROE and taxes in the volumetric rates developed in D.87-12-039 as well. DRA says the logic for including preferred equity in volumetric rates is identical to the reasoning for including common equity and associated taxes--it maximizes the utility's incentive to provide service; i.e., to move gas through the system. In this proceeding, DRA is asking the Commission to formalize an "unwritten rule" dating back to the implementation of the new gas regulatory framework.

This controversy has more to do with semantics than with ratemaking; or more precisely, with the imprecision of language. In ratemaking "return on preferred equity" is a separate and distinct concept from "return on common equity"; and "return on equity" and "return on common equity" are synonymous. The question presented is not whether "return on preferred equity" is or is not included in "return on equity," the question is whether we should include return on preferred equity in volumetric rates. We have reviewed the prior SoCal ACAP and PG&E ACAP and find that DRA is correct: in both cases return on preferred equity was included in volumetric rates to the extent that return on common equity was included. We have been given no reason to change this allocation.

The second UEG rate design issue involves the allocation between UEG volumetric tiers of FERC authorized take-or-pay direct billings. SoCal has proposed to spread take-or-pay costs allocated to UEG customers only to the UEG Tier I volumetric rate. DRA has proposed to spread these costs over the UEG Tier I and Tier II rates. DRA's position makes DRA's proposed UEG Tier II rate about 75% higher than SoCal's proposed UEG Tier II rate.

The rates adopted in SoCal's last ACAP in D.90-01-015 included take-or-pay costs only in the UEG Tier I rate. DRA contends that this was a mistake and that Appendix C to D.90-01-015 which allocated the costs exclusively to Tier I volumes directly conflicted with the language of the decision at p. 104 to "maintain the current basis for setting UEG rates, and the current two tier rate structure." D.87-12-039 outlined the "current basis for setting UEG rates" referred to in D.90-01-015. The Commission in D.87-12-039 stated that the current volumetric rate design practice is to recover "transition cost items placed in the volumetric rate...over all forecasted UEG throughput....Thus, the Tier I rate will be set to exceed the Tier II rate by the amount necessary to recover the remaining one-half of the A&G cost item over the Tier I volumes." (D.87-12-039 at p. 99.)

SoCal argues that over the past several years the Commission has consistently adopted and supported a two-tier declining block volumetric rate design for UEG customers, principally to keep the tailblock low so that electric utilities may obtain lower prices for purchased power and non-gas fuels. Potential suppliers of power or fuel must beat SoCal's low Tier II transportation rate. This principle was expressed in D.90-01-015, at p. 104:

> "...this rate design structure gives UEG customers leverage in negotiation favorable non-gas fuel and power purchases. This leverage is reduced to the extent volumetric charges are increased."

DRA believes that by loading these costs on the Tier I rate, essentially UEG firm load, SoCal will be grabbing the revenue and avoiding the risk. DRA's argument is persuasive. DRA is correct in stating that cost recovery in Tier I is less risky to the utility than cost recovery in Tier II. Of course, a low Tier II rate will make it less likely that UEG customers will switch to other fuels or power and, if they do shift, will assure the UEG customers of very low alternate fuel costs, thus benefiting the UEG's ratepayers. But the rate proposed by SoCal goes beyond that needed to reduce fuel switching. Under the SoCal proposal the resulting tier structure is unreasonably skewed, with a Tier I rate of 13.7¢ per therm and a Tier II rate of 1.7¢ per therm, as compared to the 5.3¢ and 1.5¢ per therm split from D.87-12-039. The rate structure adopted in D.90-01-015 contradicted the reasoning of the decision; we should follow the reasoning, not the rate structure.

D. Franchise Fees and Uncollectibles

SoCal and DRA differ regarding recovery of F&U allocated to noncore customers. SoCal proposes to spread noncore F&U costs between noncore demand and volumetric rates in the same proportion as total system costs are allocated between demand and volumetric rates. DRA proposes to spread noncore F&U costs only to volumetric rates.

SoCal argues that the amount of franchise fees and uncollectibles is a function of revenues. If more or less volumes are delivered to customers, actual franchise fees and uncollectible costs to SoCal will vary according to the effect changed volumes have on total revenues through the application of volumetric and demand charges. If, as DRA recommends, all F&U costs (including those associated with revenues from demand charges) are loaded into volumetric rates, then variations in throughput will cause SoCal to undercollect or overcollect its actual franchise fees and uncollectibles costs. If SoCal's proposal for a proportional spreading of F&U costs between demand and volumetric charges is adopted, then changes in revenues to cover F&U will be proportional to changes in total revenues produced by variations in throughput. SoCal declares that the Commission specifically addressed and endorsed SoCal's treatment of F&U costs in D.88-03-085, but admits, nevertheless, that the rates adopted in D.90-01-015 spread noncore F&U costs only to volumetric rates.

DRA contends that SoCal's intended recovery of F&U in customer and demand charges rather than volumetric charges is clearly contrary to D.87-12-039, where the Commission stated unequivocally that F&U should be placed in volumetric rates. (At pp. 94 and 98.) And, DRA points out, the Commission followed D.87-12-039 in its rate structure in D.90-01-015. We do not agree with SoCal's interpretation of D.88-03-085. That decision did not modify the F&U treatment of D.87-12-039.

Both parties have cited scripture to bolster their position on F&U. DRA's being the most current exegisis, and used in SoCal's last ACAP, will be adopted.

E. <u>Excess Commodity Gas Cost</u>

SoCal and DRA differ with respect to the rate design for excess commodity gas costs allocated to noncore customers. SoCal proposes to include those costs in the noncore customers' demand charges, while DRA proposes to include them in volumetric rates, a riskier proposition for SoCal. SoCal argues that in December 1986, December 1987, and January 1988 when these gas costs were incurred, the Commission's Consolidated Adjustment Mechanism provided assurance to SoCal of dollar-for-dollar recovery of all prudently incurred gas costs, regardless of any variations in throughput from forecast levels. SoCal incurred these costs in reliance on the

Commission's then existing regulatory scheme and was not found to be imprudent. Therefore, SoCal argues, the Commission should allow it to reflect these costs in noncore demand charges, which are less risky than noncore volumetric rates.

DRA disagrees. It argues that these are commodity costs, volumetrically incurred, and consequently should be volumetrically recovered. It reasons that these costs, whether or not they are reasonable, are avoidable, and therefore SoCal's customers should not automatically be burdened with them. Rather, customers should have the same opportunity to avoid them as SoCal had. Additionally, DRA states that demand charge treatment would provide SoCal with little incentive to prevent imprudent incurrence of such losses, since the bulk of the cost recovery would be guaranteed rather than earned.

We agree with DRA. Gas costs are not recoverable through demand charges. Even during the period when SoCal incurred the costs, the costs were recoverable through commodity charges. SoCal was never guaranteed a 100% recovery. Further, should our throughput forecast prove too low, SoCal has the potential of added revenues in excess of costs.

F. <u>Wholesale Rate Design</u>

In developing rates for Long Beach, SoCal contends that it has adhered to the Commission's rate design for wholesale customers adopted in previous decisions, consistent with the direction of the Commission in D.90-01-015 and D.90-01-021 not to consider major rate design changes. Long Beach's current rate design contains fixed demand charges plus a single (non-tiered) volumetric charge that is equal to the weighted average of UEG Tier I and II rates at forecast volumes.

Long Beach asserts that the current rate design puts it at a competitive disadvantage to provide above-forecast levels of service to Edison plants in Long Beach that SoCal also serves. Long Beach claims that Edison would pay SoCal a lower incremental rate the (UEG Tier II rate) for additional transmission service than the incremental rate Long Beach would pay to SoCal (the single wholesale volumetric rate) to receive more transmission service for redelivery to Edison by Long Beach. Long Beach has proposed an alternative rate design that simply reverses the relationship rather than equalizing SoCal's tailblock rates to Edison and Long Beach. Long Beach has proposed a two-tier volumetric rate design for SoCal service to Long Beach. The two-tier rate structure incorporates the demand charge/volumetric charge considerations embodied in the retail UEG rate design by setting the average Long Beach volumetric rate equal to the average retail UEG volumetric rate. However, it provides Long Beach the opportunity to serve incremental Edison demand by setting the second-tier volumetric rate equal to the floor rate specified by the Commission in D.87-12-039.

Long Beach asserts that this rate design proposal produces the same revenue for SoCal as does SoCal's own proposal, at the adopted level of throughput. To the extent that Long Beach serves additional volumes, SoCal already will have been compensated for the allocated cost of serving Long Beach. Incremental revenue in excess of incremental cost will benefit SoCal. Long Beach says that SoCal's incremental cost of serving Long Beach is relatively low and the Commission's adopted floor rate is indirectly an allowance for incremental cost. This rate design proposal, in the opinion of Long Beach, allows SoCal to recover the incremental cost, plus a positive contribution to margin.

Under Long Beach's proposal, its incremental rate would be far below SoCal's incremental rate to Edison and would barely cover SoCal's out-of-pocket expenses. If Long Beach is correct that the current rate design provides a competitive advantage to SoCal in serving Edison plants in Long Beach, then Long Beach's proposal would provide a competitive edge to Long Beach. SoCal is willing to accept either the existing rate design for Long Beach or a rate design that establishes incremental rates that are equal for the two customers. However, SoCal states that its costs to deliver one incremental unit of gas to Long Beach are not less costly than delivery to Edison, and SoCal objects to a rate design that implies to the contrary.

SoCal and DRA have proposed a rate design for Long Beach which follows the principles of the rate design in D.90-01-015. We will adopt that rate design. A rate design change as proposed by Long Beach has many ramifications which are best dealt with in a separate proceeding so that if changes are warranted they will be in place prior to SoCal's next ACAP and all parties can prepare forecasts based on those known changes. Therefore, we will keep A.90-03-018 open for the purpose of reconsidering the rate design proposal of Long Beach. By this reference we do not express any opinion on the merits of Long Beach's proposal.

G. <u>Residential Rate Design</u>

SoCal, DRA, and TURN differ with respect to residential rate design. SoCal has approached residential rate design with two principles in mind: (1) residential rate design should better reflect cost incurrence; and (2) the still excessively high residential tailblock (Tier II) rate should be reduced as much as possible. These principles led SoCal to propose an increase its residential customer charge from $3.10 per month to $5.00 per month and to use the revenues this increase would generate (above the increase in residential class revenue requirement for this case) to reduce the residential Tier II volumetric rate. SoCal states that its cost studies show that residential customer related costs are over $10 per customer per month. SoCal made this same argument in its prior ACAP, (D.90-01-015 at p. 93) which rejected SoCal's proposed increase in the customer charge, and supported the principle of recovering more revenues through volumetric residential rates. We based our holding on three grounds: (1) it gives a customer more control over his total bill (because volumetric charges can be avoided through less consumption, but customer charges are unavoidable); (2) it gives more incentive for conservation; and (3) it maintains an appropriate share of risk between ratepayers and the utility.

SoCal claims that the third ground is incorrect because the core balancing account makes it indifferent to variations in core throughput (except for core take-or-pay costs subject to a "one-way" balancing account). The remaining two grounds, according to SoCal, are not compatible with ratemaking principles. It is one thing to design rates so a customer can better control his total bill and avoid paying for costs that he does not impose on the system, but it is another thing entirely to allow him to avoid paying a cost he does impose on the system. In this case customer costs are $10 per month regardless of the amount of gas taken. Rates should not be designed to allow a customer to avoid paying the costs the customer has created.

SoCal believes the concern expressed about "conservation incentives" is inconsistent with other directions from the Commission that the residential Tier II rate is too high and should be reduced as quickly as possible. PU Code § 739.7 states: "In establishing residential rates, the Commission shall reduce high nonbaseline residential rates as rapidly as possible." The Commission has said in D.88-10-062 and D.90-01-015 that Tier II rates are too high. Because SoCal's proposal would not reduce Tier I rates, it cannot be judged to be anticonservation for consumers whose consumption does not exceed the Tier I volume. SoCal's increased customer charge will reduce Tier II rates, but this is what the Commission and Legislature have said they want.

SoCal urges that regardless of our position on the proposed customer charge increase, the relative level of Tier I and Tier II residential rates must be addressed. If the Commission does not increase the residential customer charge, SoCal requests that the Commission reduce the current residential Tier II rate from the present 75¢/th level to about 70¢/th and increase the Tier I rate a sufficient amount to produce the Commission-adopted residential class revenue requirement.

DRA does not oppose SoCal's proposed customer charge increase; TURN does oppose it. DRA recommends that the difference between residential Tier I and Tier II rates be reduced by 20%; this is in contrast to the roughly 50% closure proposed by SoCal. TURN supports DRA. DRA proposed a less extreme reduction in order to avoid excessive rate increases for residential customers. It claims that SoCal's proposal is an overzealous attempt to reduce the tier differential. The SoCal proposal of an approximately 50% reduction in the baseline/nonbaseline differential is almost identical to two recent PG&E proposals which the Commission soundly rejected. In the PG&E general rate case, the Commission adopted a 25% reduction in the tier differential (D.89-12-057 at pp. 262-263); in the PG&E ACAP, a 20% reduction was adopted (D.90-04-021 at pp. 73-75). In last year's SoCal ACAP, the tier differential was closed by about 18% (D.90-01-015 at p. 95 and Appendix C at p. 2). Most recently, in the SDG&E ECAC, the Commission adopted DRA's proposal for a 20% closure. (D.90-05-090 at pp. 4 and 11.)

DRA acknowledges that Section 739.7, directs the Commission to "reduce high nonbaseline residential rates as rapidly as possible." But, DRA believes that that language must be implemented in conjunction with the directive found in Section 739(c)(1), to "avoid excessive rate increases for residential customers." DRA recommends a 20% reduction in the rate differential as striking the most appropriate balance between the legislative directives to reduce high nonbaseline residential rates as rapidly as possible, and at the same time avoid excessive rate increases for residential customers. Assuming no customer charge increase, the maximum Tier I winter bill increase of $2.13 approximates a 5% increase over the percentage class increase. DRA believes that SoCal's proposal results in an unacceptably large bill impact on high-end baseline customers unprotected by LIRA.

We will not adopt SoCal's proposal to increase customer charges from $3.10 per month to $5 per month. SoCal made the same request in its prior ACAP and we rejected it; we are not persuaded to change. In D.90-01-015 we said the lower demand charge permitted greater customer control over gas use, maintained an appropriate balance of risk between ratepayers and utilities, and maintained conservation incentives. We will adhere to those reasons.

DRA's proposal to reduce the rate differential between Tier I and Tier II by 20% is reasonable and will be adopted. It is in conformity with our prior SoCal ACAP where we closed the gap by about 18%; with the recent SDG&E ECAC where we closed the gap by about 20%; and the recent PG&E ACAP where we closed the gap by about 20%.

VII. <u>Cost of Gas - SDG&E</u>

SDG&E's core portfolio comprises primarily spot gas and contract gas priced at close to spot. SDG&E's noncore WACOG is entirely spot gas. Due to the differences in DRA's and SDG&E's spot gas price forecasts, the core and noncore WACOG price estimates differ. LUAF and company-use gas estimates differ because of differences in the throughput forecasts.

A. <u>Core WACOG</u>

For the core WACOG, DRA estimates that SDG&E will purchase gas for the core portfolio at a weighted average price of $2.18/Dth. SDG&E estimates a weighted average price of $2.42/Dth. Over the last few years SDG&E's core portfolio has been comprised of almost all spot gas or contracts which provide SDG&E with gas at a price close to the average spot market price. Both DRA and SDG&E expect that this will continue to be the case throughout the ACAP period. The differences between DRA's and SDG&E's core WACOG is due mainly to the differences between the parties' respective spot gas forecasts.

B. Noncore WACOG

DRA estimates that SDG&E will purchase gas for its noncore portfolio at an average weighted price of $2.21/Dth. SDG&E estimates an average weighted price of $2.38/Dth. The difference is due primarily to the two different spot gas price forecasts.

C. LUAF Gas and Company Use Gas

For the ACAP period, SDG&E estimates 708 MDth of LUAF gas and 273 MDth of company use gas. Using DRA's forecast of total throughput, DRA estimates 781 MDth for LUAF gas volumes, and 299 MDth for total company use gas volumes.

D. Discussion

Because SDG&E buys in the same market as SoCal we would expect it pays about the same price for spot gas. We will, therefore, adopt a spot gas price for SDG&E of $2.50/Dth. In SDG&E's last ACAP we adopted the same spot gas forecast for both SoCal and SDG&E; there is no reason for us to change.

VIII. Throughput Forecast - SDG&E

This section will discuss only the UEG forecast, the only area in which DRA and SDG&E differ. DRA's econometric throughput models forecasted the residential, commercial, and noncore industrial demand for SDG&E's customers. Both SDG&E and DRA concur in the forecast of gas demand from these three customer groups. SDG&E accepts DRA's residential throughput forecast. DRA accepts SDG&E's commercial throughput forecast and noncore industrial throughput forecast (which includes cogeneration transportation volumes).

A. UEG Forecast

Different forecasts of SDG&E's UEG gas demand were presented by DRA, SDG&E, and SoCal. All three use the same ELFIN model except that each party used its own fuel price and economy energy assumptions. DRA forecasts UEG demand of 42.97 MMDth for SDG&E. This forecast does not reflect any economic fuel switching during the ACAP period by SDG&E based on DRA's forecast of fuel prices. SDG&E forecasts UEG throughput of 32.285 MMDth. SDG&E also forecasts 7.20 MMDth of economic fuel switching in December 1990 and January 1991. SoCal forecasts 38.6 MMDth of UEG gas demand from SDG&E and 4.70 MMDth of fuel switching. If there is no economic fuel switching the three UEG throughput forecasts would vary by only a slight amount. DRA forecasts no fuel switching.

SDG&E asserts that it is able to lower fuel costs during the ACAP period by purchasing oil when it is less expensive than the future expected cost of gas. SDG&E has already purchased a significant volume of oil at a price of $12.05/Bbl FOB Singapore. SDG&E states that if actual gas dispatch prices in later ACAP period months exceed that price, then SDG&E will burn oil in those months at a savings. It believes that for purposes of calculating expected fuel switching, gas prices must be compared to oil price in inventory, not forecast prices of oil. Thus, even if oil prices are high in the future, fuel switching will still occur to the extent that SDG&E has oil in inventory at a lower dispatch price.

We agree with DRA that there should be no fuel switching due to lower oil prices. For purposes of calculating expected fuel switching, gas prices should be compared to the replacement price of the oil burn, not to the oil price in inventory. The only exception to this comparison is if a utility has an excess of oil over its normal fuel oil inventory level. There is no evidence that SDG&E has such an excess. It is imprudent to burn $12 oil which must be replaced by $24 oil when there is natural gas available at a price less than the $24 equivalent.

IX. Rate Design - SDG&E

A. Residential Tier Closure

SDG&E recommends reducing the Tier II - Tier I ratio from 1.742 to 1.496 by allocating all the residential class rate reductions to Tier II. DRA recommends reducing the rates in both tiers to achieve a final ratio roughly equivalent to SDG&E's ratio. This gradual reduction of the tier differential has the added advantage of sharing the proposed ACAP rate decrease with customers whose usage does not exceed the baseline allowance. Because DRA's proposal shares the rate decrease with customers when usage does not exceed the baseline allowance, we will adopt it.

B. Rate Design Methodology

DRA includes preferred equity in ROE and taxes. Our resolution of this allocation was extensively discussed in regard to SoCal's rate design, which we will follow for SDG&E.

C. Schedule GL-1 - Borrego Springs Roadrunners

The Roadrunner Club is a 326-space mobile home park located in Borrego Springs, California. Borrego Springs is a community of about 3,000. There is no natural gas service in Borrego Springs. Except for the Roadrunners Club all residents are on either all-electric service (1186 customers) or propane service (462 customers). Roadrunners is the association of mobile home owners within the Roadrunner Club. Wright & Company is the owner of the Roadrunner Club. The interest of Roadrunners in this proceeding is limited to the liquified natural gas (LNG) service provided by SDG&E to the Roadrunner Club. Three hundred and nineteen of the spaces are plumbed for LNG service and the remaining seven are all-electric. SDG&E serves the LNG customers within the Roadrunner Club on Rate Schedule GL-1. Residential rates charged under GL-1 are identical to the rates charged under SDG&E's Schedule GR (and GR-LI where appropriate), except that GL-1 imposes an additional domestic-use facilities charge and minimum charge on each monthly bill. Currently, the GL-1 facilities charge is $13.10 per month for domestic use. The minimum charge equals the facilities charge. The Roadrunner Club customers are the only SDG&E customers served under GL-1. They are also the only remaining LNG customers of SDG&E. Schedule GL-1 was closed to new customers on January 1, 1984. SDG&E proposed phased-in full cost-based rates for the Roadrunner Club LNG service by increasing the monthly facilities charge in four successive steps:

Effective Date	Facilities Charge
10/1/90 (or eff. date of rates resulting from this case)	$16.49/month
4/1/91	$25.47/month
10/1/91	$38.94/month
4/1/92	$52.41/month

The SDG&E proposal is based upon the result of an SDG&E cost study which concluded that the annual cost of service to the Roadrunner Club is $277,521 while revenue at current rates is only $128,468, leaving a deficit of $149,053. The differential is primarily due to the cost of LNG exceeding the cost of natural gas. The proposed facilities charge of $52.41/month, to be in effect as of April 1, 1992, is designed to recover 100% of the annual costs, when combined with the current Schedule GR revenues from LNG sales to the Roadrunner Club customers.

DRA accepts SDG&E's basic approach but modified the SDG&E proposal in two respects:

1. The revenue deficit is subdivided into fixed and commodity portions. Schedule GL-1 is redesigned to collect the commodity portion as a per therm surcharge over and above the Schedule GR charges.

2. The full-cost phase-in schedule is stretched from 18 months (SDG&E's proposal) to three years.

DRA's proposal, then, is as follows:

Effective Date		Charges
10/1/90	Facilities Commodity	$13.82 $ .09653 per therm
10/1/91	Facilities Commodity	$15.46 $ .31373 per therm
10/1/92	Facilities Commodity	$17.90 $ .63952 per therm
10/1/93	Facilities Commodity	$20.35 $ .96531 per therm

SDG&E does not object to DRA's rate proposal.

Roadrunners propose that the club customers be placed directly on Schedule GR (or GR-LI as applicable) and Schedule GL-1 be eliminated. In addition, SDG&E should be directed to either (1) confirm its intention to permanently serve LNG to the Roadrunner Club without further attempts to apply special rates or (2) promptly propose and file an orderly and equitable Roadrunner Club LNG service abandonment plan for Commission approval. In the alternative, Roadrunners propose that should the Commission adopt SDG&E's basic approach of full cost-based rates, SDG&E should be ordered to restudy costs of service using practices more accurate and consistent with Commission-approved cost determination and ratemaking. In addition, Roadrunners prefer DRA's modification of the SDG&E basic approach.

Roadrunners argue that SDG&E's proposed increase represents an overall average increase of 116% in the Roadrunner Club residents' annual bills. Individual customer impacts will depend upon the season and upon the therms used. In summer months those customers paying only the minimum charge will realize a 300% bill increase ($13.10 to $52.41). In winter months, large users will experience a less-than-average percentage increase. Future increases will be higher as SDG&E said that $107,153 in facilities improvements are underway.

Roadrunners assert there is no justification for SDG&E's proposing full cost-based rates for LNG residential customers. Initially, in 1968, the Commission adopted LNG tariffs to recover the full cost of LNG service. At that time, the cost of LNG comprised about 10% of the total cost. Based on the SDG&E 1990 cost of service study, the cost of LNG now constitutes well over 70% of the total cost. Thus, in today's reality, SDG&E's proposed increase to the "facilities charge" is a misnomer because the actual purpose of the increase is to recover LNG commodity costs.

Roadrunners point out that in 1968 SDG&E's residential gas rates were based, in part, upon a customer's geographic location in the service area. There existed four basic rate areas reflected in four different rate schedules, G-1 through G-4. When the Commission approved expansion of the SDG&E service territory to include the remote Borrego area, it approved rates specifically calculated for the Roadrunner Club. The GL-1 schedule, as originally adopted, imposed a facilities charge of $6.35 plus a somewhat modified version of rates applicable under Schedule G-4. However, in D.87586, for rates effective in July 1977, the Commission abolished SDG&E's geographic rate areas and placed all residential customers on a single rate schedule. Thus, Roadrunners argue, neither today's residential cost of service calculations or residential rates, depend upon a customer's physical location in the service territory. Systemwide averages are reflected.

Roadrunners believe that SDG&E's current cost studies are not based on previous cost studies but are rather based on a present-day effort to go back to day one and recover the full cost of LNG service forgetting the intervening changed circumstances and Commission rate practices. It results in classifying the Roadrunner Club residents differently than other SDG&E residential customers and penalizes them for using LNG. Roadrunners claim that they have been singled out unfairly. They argue that under SDG&E's single rate design there is a large class of customers who are assigned to a single rate schedule and there exist customers who pay more than the cost to serve them averaged in with customers who pay less than their cost of service. A comparison in distribution costs between a Roadrunner Club customer and a new single-family dwelling leads to the conclusion that the Roadrunner Club customers are probably less costly to serve than the average new single-family dwelling in the SDG&E territory.

Roadrunners contend that the deficit SDG&E seeks to recover would cost the general SDG&E residential ratepayer roughly 0.036 cents per therm, and infinitesimal amount which should be weighed against the proposed 116% average annual increase. Roadrunners urge that the GL-1 schedule be eliminated and that they be served directly on Schedule GR. In addition to proposing an alternate rate schedule, Roadrunners took issue with SDG&E's cost of service study in four areas: cost of LNG, operating and maintenance (O&M) costs, capital recovery, and A&G costs.

1. <u>LNG Commodity Costs</u>

SDG&E forecast a commodity cost of $200,362 for the ACAP period, while Roadrunners forecast $140,253 (a difference of $60,109). SDG&E's estimate of LNG commodity costs is based on a sales forecast of 125,938 therms. Over the last four years, recorded sales to Roadrunners have been 127,323, 127,455, 126,937, and 125,938 therms per year respectively.

SDG&E states that the price of LNG used is $1.59 per therm which is the actual price paid by SDG&E under its current supply contract. The current contract reflects the lowest price LNG available to SDG&E for the quality of LNG desired. While lower price supplies have at times been available, in the past SDG&E has experienced serious operating difficulties with these supplies due to poor quality. The poor quality LNG caused increased O&M expenses due to repeated service calls by Roadrunners.

Roadrunners claim that they are at risk for fuel costs, in that any overcollection by SDG&E caused by lower LNG commodity costs is not returned to customers. SDG&E has no objection to establishing a fuel balancing account for LNG customers, such that any lower fuel costs experienced by SDG&E will be returned to LNG customers in subsequent ACAP rates.

2. <u>O&M Costs</u>

SDG&E's forecast of O&M costs ($39,182) is based on historical information and a qualitative assessment from SDG&E's gas operations department. The estimate used is the average recorded O&M costs for the period 1986 through 1989. Roadrunners have forecast $5,565, or $33,617 less than SDG&E's estimate.

3. <u>Capital Recovery Costs</u>

Capital recovery costs or carrying charges are costs associated with return of investment, taxes, and return on investment for LNG-related facilities. SDG&E forecast $28,126 in carrying costs, while Roadrunners forecast $18,750, a difference of $9,376. There are at least two alternatives associated with the estimate of annual carrying charges. The year-by-year methodology results in high annual charges initially that decline gradually reflecting depreciation of the investment. The levelized annual carrying charge (LACC) methodology develops a uniform carrying charge for the book life of the investment. Both alternatives result in equal costs to ratepayers over the long-term (present value of revenue requirements over the investment book life are equal). SDG&E chose the LACC methodology in its cost of service study because it is widely used and provides for a more uniform cost factor for rate purposes.

LNG facilities were first installed in 1968 and a significant expansion was completed in 1977. The vintage of the facilities would suggest that carrying costs factors in 1990 would be higher under the LACC method. However, over the long-term SDG&E believes no significant difference exists. In 1990, SDG&E will incur $110,000 in additional investment to serve Roadrunners facilities (a 62% increase of current investment at original cost).

For these incremental investment costs the LACC would result in lower carrying cost factors.

4. A&G/Common Plant Costs

SDG&E's estimate of $9,851 is based on historical average data for A&G and common plant expenses as a percentage of capital investment. This methodology is commonly used by SDG&E as an estimate of expenses in other rate proceedings. Roadrunners estimate A&G expenses of $4,661.

5. Discussion

A proper analysis of the issues raised by Roadrunners requires information regarding the utility bills of other customers in Borrego Springs. Roadrunners want to be served on SDG&E's natural gas schedule despite the fact that SDG&E has no natural gas service in Borrego Springs. The current estimated average customer's bill for gas and electric service in Borrego Springs is:

	Roadrunners	All-electric
Gas[3]	$33	$ 0
Electric	37	79
Total	$70	$79

A comparison of present and proposed average Roadrunners bills:

	Present	Roadrunners Proposed	SDG&E Proposed (As of 4/1/91)	SDG&E Proposed (As of 4/1/92)	DRA Proposed (As of 10/1/90)	DRA Proposed (As of 10/1/93)
Gas	$33	$19.90	$43.37	$79.31	$35	$79.31
Electric	37	37.00	37.00	37.00	37	37.00
TOTAL	$70	$56.90	$80.37	$116.31	$72	$116.31

3 The LNG gas estimate includes the $13.10 facilities charge.

The average SDG&E systemwide monthly bill for customers who use natural gas is $30.35. One estimate of converting the mobile home to all-electric service is $8,000 a unit. Roadrunners complain that it is unfair to raise their rates because they should be treated as if they were part of the class of residential gas users and should only pay the rates which natural gas users pay. If Roadrunners were in a territory surrounded by natural gas users within easy access to a natural gas line its argument would have merit, but considering Roadrunners' location amid all-electric homes and propane gas homes, to accede to its request would be discriminatory. Roadrunners seek a lowering of their gas costs to about $20 and all-electric users are paying even more for equivalent service.

Under the logical extension of Roadrunners' theory all residential users should be paying about the same rates. We are not prepared to declare such a policy. We do, however, believe there are limits to the amount of costs which one small group of customers should absorb. As LNG bills increase to a static group of customers, the customer base is likely to decrease thus thrusting more overhead costs on fewer customers. This result would impinge on our duty to provide all customers with access to service at reasonable rates. Therefore, we will not approve rates that would increase the Roadrunners' average combined LNG and electric bill to exceed the average Borrego Springs all-electric users bill. Admittedly, such comparisons are based on averages and estimates and will not result in exact equivalences, but that should not deter us from fixing reasonable rates for Roadrunners. When considering the relative cost of LNG and electricity in the Borrego Springs area we believe that DRA's proposal for rates to be effective October 1, 1990 for the forecast year is reasonable. Rates for future years for Roadrunners are not approved.

In regard to the dispute over LNG commodity costs, O&M costs, capital recovery costs, and A&G costs we believe that SDG&E's calculations, which have been reviewed and accepted by DRA, are reasonable.

X. Miscellaneous

A. Mobile Home Master Meter Charges

WMA seeks to modify the master meter/submetered rate schedule applicable to mobile home parks served by SoCal on Rate Schedules GS and GSL.

Pursuant to PU Code § 739.5 the Commission is to set rates applicable to master metered/submetered mobile home parks to provide a sufficient differential (discount) to cover the reasonable average costs of providing submetered service, with a limitation that the discount shall not exceed the average cost the utility would have incurred in providing comparable services directly to the residents in the mobile home park. Currently, that discount is set at a monthly average of $5.40 per space.

In the 1989 SoCal ACAP proceeding, SoCal provided data showing its comparable monthly costs of submetering at $6.36 per space and WMA requested that the discount be increased to that level. However, WMA had not submitted a cost of service study on behalf of mobile home park owners. In the absence of cost data the Commission made no change in the discount and directed WMA to raise the issue again once a study had been prepared.

WMA has submitted on behalf of master metered/submetered park owners a cost of service study reflecting a reasonable monthly average cost to provide submetered service in the SoCal territory for 1990 as $8.91 per space.

SoCal claims that its 1989 cost of $6.36 per space per month from its 1989 ACAP proceeding is the most current cost information available. SoCal accepts WMA's study results and does not oppose the recommendation of WMA that the Schedule GS and Schedule GSL discounts be increased to $6.36 per space per month. DRA similarly does not oppose increasing the discount to $6.36 per month per space.

We will set the Schedule GS and GSL mobile home submetering discount at a monthly average of $6.36 per space, which shall be reflected in the daily credit.

B. The Gas Balance Model

SoCal used its Gas Balance Model (GBM) to calculate forecasted levels of curtailments. DRA performed an analysis of the GBM model and provided recommendations with respect to the use of the GBM model in ACAP proceedings. In general DRA concluded that the GBM offers a useful analytic methodology for the ACAP. However, DRA believes that additional investigation could profitably be conducted to address the following issues: the nature and impact of the respecification of the contract deliveries and the relationship of the specification and values in the model to the actual contract terms; the nature of the support for parameter values, particularly the upper and lower bound values for inventory storage, injection, and withdrawal. DRA also believes that SoCal should present a more integrated view of the role which the GBM plays in SoCal's operation, capacity expansion, and gas purchase decisions. Finally, DRA recommends that the scope of GBM be expanded to include the specification of separate inventories for the G-STAQ and G-STOR programs. DRA also recommends that for the next ACAP, SoCal present GBM output with these separate inventories and with a horizon which extends from the beginning of the G-STAQ and G-STOR program period in Spring 1991, through the ACAP period. Moreover, DRA recommends that the customers using G-STAQ and G-STOR file support for their use of this inventory.

SoCal does not dispute the fact that changes in regulations and in industry conditions in general may periodically require review and revision of the role of the GBM, but it does not believe that the briefing stage of an ACAP is the appropriate place to conduct that review. It is willing to have its technical experts on the GBM meet with DRA and TURN or other parties to discuss possible refinements to the GBM. It points out there are technical and logistical difficulties and limitations which must be considered in any such discussion, and which can be better addressed by technical experts rather than by having attorneys discuss them in a brief.

We agree with SoCal. Any changes DRA seeks in the GBM are best worked through the respective technical staffs of the parties. We do not wish, by order, to inadvertently limit the scope of the discussions.

C. Requests for Findings of Eligibility

Pursuant to Rule 76.54 of our Rules of Practice and Procedure, TURN and the Roadrunner Club Association, Inc. request a finding of eligibility for compensation in this proceeding. TURN has been found eligible for compensation for calendar year 1990 in A.89-08-024 and, therefore, pursuant to Rule 76.54(a), is found eligible in this proceeding.

The Roadrunner Association's request alleges that the Association is a non-profit corporation whose members are mobilehome owners or tenants within the Roadrunner Club, a space mobilehome park located in Borrego Springs, California. Wright and Company (Wright) are the owners of the Roadrunner Club and joined the Association as an interested party in this proceeding. The Roadrunner Club and the Association members are the only remaining LNG customers served under Rate Schedule GL-1. Three hundred nineteen of the 326 residential spaces in the Roadrunner Club are plumbed for gas service and the remaining seven are all electric.

The Association alleges that it represents an interest, LNG customers served by Schedule GL-1, which would not otherwise be adequately represented in this proceeding, and whose representation is necessary for a fair determination. SDG&E in this application proposes to increase the LNG customer's monthly facilities charge from $13.10 per month to $52.41 per month, an overall increase of 116% in the Association members' annual bills. The Association alleges that the DRA represents the interests of all classes of public utility customers and cannot be an adequate representative of a particular class, or in this case what should be deemed a subgroup of a particular class (residential). In fact, DRA accepted SDG&E's proposal making only two modifications in an effort to minimize the effects of the increase and extend the phase-in period to lessen the immediate impact.

The Association alleges that it cannot afford to pay the costs of effective participation and that the economic interest of the individual members of the Association is small in comparison to the costs of effective participation. The Association is a voluntary organization with dues set at an annual amount of $10. Income for the Association is derived primarily from dues and special assessments. Approximately six years ago, the Association anticipated having to institute legal action and did a special voluntary assessment. At the end of 1989, that special legal fund had a balance of $33,694. Prior to joining as interested parties in this proceeding, Wright and the Association agreed to pay the costs and expenses on a respective split of 40% and 60%. Thus, the Association is incurring 60% of the total expenses.

The Association asserts that its financial position will, and has been, greatly diminished due to the unanticipated need to participate in this proceeding and further judicial review. Furthermore, the economic interest of individual members is small in comparison to the costs of effective participation. The members average monthly LNG bill over a 12-month period ranges from $16 to $42 and is miniscule in comparison to the cost of participation. The budget for the Association and Wright for this case is approximately $29,400. The Association estimates that its request for compensation will be $17,640 (60% of budgeted total) for its participation in this SDG&E 1990 ACAP proceeding. This is based on 120 hours of attorney time at $125 per hour for a total of $15,000, plus 120 hours of expert witness fees at $95.00 per hour for a total of $11,400 and $3,000 for other reasonable costs, primarily postage, telephone, facsimile, photocopying, and travel expenses.

We commend the Association on its forthrightness in its estimate of its budget for this proceeding and in its source-of-funds disclosure. But with an estimated budget of $17,640 and a legal fund with assets of $33,694, we cannot find that there will be significant financial hardship within the meaning of Rules 76.52(f) and 76.54(a). Therefore, we conclude that its request for a finding of eligibility for compensation must be denied.

It is not enough to show that the economic interest of the individual members of a group is small in comparison to the costs of effective participation in the proceeding (Rule 76.52(f)(2)). A customer must also show that it cannot afford to pay those costs (Rule 76.54(a)(1)). "The request shall include...a summary of the finances of the customer...." Rule 76.52(f)(2) must be read in conjunction with Rule 76.54(a)(1). Otherwise, entities such as the California Manufacturer's Association, the California Trucking Association, and any group that can assess members for costs could be eligible for compensation.

Customers who can pay for representation cannot claim eligibility. (Re 976 Information Access Service D.86-05-007 in I.85-04-047 and C.85-04-021; cf. Re PG&E D.89-10-037 in A.86-04-012, Power Users Protection Council found eligible.)

D. Proposed Decision

This decision was originally issued as a Proposed Decision. Comments of the parties to the Proposed Decision have been considered. To the extent the comments pointed out technical errors, those comments have been adopted; to the extent the comments asserted legal error we have made no changes. The

Roadrunner Club commented that it is concerned that it will have to appear every year to protect its position, which will entail substantial legal and expert witness costs. The concern is reasonable, but as we expect SDG&E to abide by our decision and DRA to protect the ratepayers, the concern should not materialize.

Findings of Fact

1. SoCal's average spot gas price forecast of $2.50/Dth for both SoCal and SDG&E is reasonable.

2. DRA's forecast of the average LSWR-delivered tax paid price of $3.59/Dth for SoCal is reasonable.

3. SoCal's propane forecast of $3.42/Dth is reasonable.

4. DRA's average LA No. 2 forecast of $5.14/Dth is reasonable.

5. SoCal's average LA No. 6 forecast of $2.95/Dth is reasonable.

6. A core WACOG forecast of $2.54/Dth for SoCal is adopted.

7. A noncore WACOG forecast of $2.54/Dth for SoCal is adopted.

8. SoCal's estimates of pipeline demand and reservation charges, and fixed costs as follows: (1) El Paso - $74,315,000; (2) Transwestern - $73,659,000; (3) PITCO - $102,300,000; and (4) POPCO - $37,996,000 are adopted.

9. A minimum purchase obligation cost estimate of $11,373,800 for SoCal is adopted.

10. DRA's forecast that SoCal will purchase 4518 MDth of federal offshore production is adopted.

11. DRA's forecast that SoCal will have zero core to noncore transfers is adopted.

12. DRA's forecast that SoCal will not purchase Elk Hills gas is adopted.

13. SoCal's estimate of $2,359,000 as the amount for the carrying costs of gas in storage is adopted.

14. DRA's and SoCal's method to determine LUAF gas, compressor fuel, and miscellaneous company use gas for the SoCal system is adopted.

15. SoCal's estimate for storage surface/migration losses on SoCal's system is adopted.

16. DRA's forecast of $63.4 million as the SoCal direct-billed portion of take-or-pay payments from El Paso is adopted.

17. SoCal shall continue to hold the Mid-La, Southland, and Chevron refunds in an interest-bearing account to be used as an offset to direct billed Account 191 costs from El Paso and Transwestern until SoCal's next ACAP proceeding.

18. SoCal's update regarding Account 191 costs appears accurate and is adopted.

19. SoCal's econometric throughput forecasts for the SoCal system are adopted.

20. SoCal's noneconometric throughput forecasts for the SoCal system (excluding the SDG&E system), modified by eliminating fuel switching, are adopted.

21. SoCal's forecast of 11.2 MMDth as the non-UEG demand for Long Beach is adopted.

22. The discount adjustment methodology consistent with the approach taken by CACD is adopted (Appendix B).

23. SoCal's forecast of interstate delivery capabilities from the El Paso and Transwestern systems, and SoCal's forecast of system availability for California gas, POPCO, and Pitas Point are adopted.

	MMcfd
California	197
POPCO	31
Pitas Point	42
El Paso	1,656
So. System	145
Transwestern	750
Interutility	150
	2,971

24. SoCal's forecast of average interutility deliveries from PG&E of 150 MMcfd is adopted.

25. SoCal's forecast of 96% El Paso availability factor is reasonable and is adopted.

26. As a result of the adopted supply and demand forecast, the average year curtailments on SoCal's system is 35,521.4 MDth. Cold year curtailment is 76,264 MDth.

27. DRA's UEG demand forecast for SDG&E is adopted.

28. DRA's recommendation that the SoCal Core Fixed Cost Account undercollection be adjusted due to an error in allocating oil revenues is adopted.

29. DRA's recommendation that the SoCal Core Purchased Gas Account undercollection be reduced by $505,500 to reflect the undercollection related to the core-elect is adopted.

30. DRA's recommendation that the SoCal Conservation Cost Account's overcollections for the core and noncore should be increased by $5.9 million and $1.3 million, respectively, to remove the Angelus litigation costs which were inappropriately charged to this account is adopted.

31. DRA's recommendation concerning the amount of credit for carrying costs that Long Beach and SDG&E are entitled to from SoCal are adopted.

32. DRA's recommendation with respect to the allocation of revenues from SoCal's pilot banking program is adopted.

33. SoCal's MAA gas should be allocated on the basis of average year throughput to P2B through P4 customers.

34. SoCal's excess commodity costs should be allocated to all noncore customers, excluding SDG&E and Long Beach.

35. SoCal's storage migration losses and the gas loss memorandum account should be allocated to all customers except EOR based on cold year season throughput.

36. SoCal's WMBE costs should be allocated on average year throughput to all customers.

37. SoCal's CCSI wholesale credit should be allocated to all customers, except EOR, based on cold year peak season throughput.

38. DRA's recommendation with respect to the calculation of the LIRA surcharge is adopted for both SoCal and SDG&E.

39. DRA's recommendations for improving SoCal's LIRA program are adopted.

40. SoCal and SDG&E shall recover LIRA costs in volumetric rates.

41. SoCal's forecast of exchange revenues for the SoCal system is adopted.

42. DRA's forecast of interutility revenues for the SoCal system is adopted.

43. SoCal's estimate of brokerage costs is adopted.

44. SoCal's recorded storage banking revenues for the SoCal system are adopted.

45. SoCal's recommendation of the amount of EOR revenues for SoCal's system is adopted.

46. DRA's recommendation to reduce SoCal's residential Tier I and Tier II rates by 20% is adopted.

47. DRA's rate design treatment of SoCal's excess commodity purchases and MAA gas is adopted.

48. DRA's rate design treatment for the UEG share of volumetric take-or-pay costs on the SoCal system is adopted.

49. SoCal's proposal to change the definition of UEG Tier I from 18.5% of throughput to 18.5% of gas demand is adopted.

50. DRA's rate design treatment of franchise fees and uncollectibles for SoCal is adopted.

51. Preferred equity should be included with return on equity and taxes in volumetric rates for both SoCal and SDG&E.

52. The forecasted balancing and tracking account balances, as presented by SoCal and updated as of July 31, 1990 are adopted. This includes the Negotiated Revenue Stability Account which was overcollected by approximately $8 million and which will be allocated to the noncore as was done in D.90-04-021 (PG&E's ACAP). SDG&E shall allocate its share to all customer classes on an average year throughput basis.

53. SoCal should be allotted a full 12-month opportunity to amortize in rates, balances accrued in Commission authorized tracking accounts before the commencement of SoCal's 1989 ACAP period.

54. SoCal's monthly residential customer charge should not be increased.

55. A core WACOG forecast of $2.50/Dth for SDG&E is adopted.

56. A noncore WACOG forecast of $2.55/Dth for SDG&E is adopted.

57. DRA's forecast of LUAF gas and company use gas on SDG&E's system is adopted.

58. SDG&E's forecast for cogeneration gas demand is adopted.

59. DRA's forecast of SDG&E's carrying costs of gas in storage inventory is adopted.

60. SDG&E's proposal to extend the period for returning the overcollections in the Implementation Balancing Account is adopted.

61. SDG&E's request to extend the revenue protection provided by the Negotiated Revenue Stability Account beyond the April 30, 1990 expiration date is rejected.

62. DRA's forecasts of residential sales and UEG demand are adopted.

63. SDG&E's forecasts of commercial demand and noncore industrial demand are adopted.

64. SDG&E should recover $1.6 million in CCSI incurred between May 1988 and mid-January, 1990.

65. SDG&E is entitled to a credit of $854,000 for CCSI collected by SoCal from SDG&E ratepayers between May 1988 and mid-January 1990.

66. SDG&E should not be allocated any of SoCal's uncollectibles.

67. SDG&E should not be excluded from SoCal's noncore CCSI balancing account.

68. SDG&E's balancing account balances and amortizations are adopted.

69. SDG&E should recover $1.631 million in rates for CCSI incurred during the ACAP forecast period.

70. DRA's recommendation to reduce SDG&E's residential Tier I and Tier II rates to a relative tier differential of 1.5 is adopted.

71. Costs of SDG&E's LIRA program should be recovered volumetrically.

72. DRA's proposed cost-based rates and phase-in proposal for Borrego LNG customers are adopted for the forecast year only.

73. SDG&E's proposed core commercial and noncore retail rates are adopted.

74. SDG&E's proposed UEG rate design is adopted as an interim modification, and only for SDG&E.

75. SDG&E's proposal to set the UEG volumetric Tier II rate equal to the wholesale rate which SDG&E pays SoCal, plus shrinkage costs, is adopted.

76. SoCal's Schedule GS and SSL mobile home submetering discount should be set at $6.36 per space per month, which should be reflected in the daily credit.

77. SDG&E residential customers taking LNG service in Borrego Springs should pay, on average, no more for combined LNG and electric service than SDG&E residential customers in the Borrego Springs area pay, on average, for all-electric service.

78. The increases in rates and charges authorized by this decision are justified, and are just and reasonable.

79. TURN is eligible for compensation.

80. The Roadrunner Club Association, Inc. is not eligible for compensation.

Conclusions of Law

1. Account 191 costs should be offset by refunds from Southland, Mid-La, and Chevron. Any net amount shall be disposed of in a later ACAP.

2. Any party may propose an allocation of Elk Hills costs in the appropriate reasonableness review proceeding.

3. SCUPP should comply with SoCal's data requests by December 1, 1990 at the latest.

4. CACD's uniform DA methodology is reasonable and all gas utilities should be required to include a DA based upon the CACD base case DA methodology in their ACAP filings.

5. Conservation related litigation costs should be entirely removed from the CCA balancing account.

6. Excess commodity costs should be allocated to the noncore customer class, including wholesale customers.

7. SoCal should close its NTCA and NFC Margin Shortfall accounts, with a transfer of the remaining balances to the NIA.

8. SoCal may extend the time needed to amortize its tracking accounts by a surcharge to be approved by CACD until January 14, 1991.

9. Noncore F&U costs should be spread only to volumetric rates.

10. The rate design issues raised by Long Beach should be resolved in our Gas Rate Design investigation I.86-06-005.

11. SDG&E's rates for LNG service to the Roadrunners Club in Borrego Springs, when added to the Roadrunners Club average electric bill, should not exceed the average bill of the all-electric residential customer in Borrego Springs.

12. Modifications to SoCal's GBM should be first discussed with the respective technical staffs of the parties and brought to the Commission for resolution only if the technical staffs reach an impasse.

13. The rate changes adopted for SoCal are set forth in Appendix C.

14. The rate changes adopted for SDG&E are set forth in Appendix D.

15. The adopted gas demand, deliveries, portfolio prices, costs, and supply forecasts for SoCal are set forth in Appendix E.

16. The adopted revenue requirement for SoCal is set forth in Appendix F.

17. The adopted cost allocation summary for SoCal is set forth in Appendix G.

18. The discount adjustment calculation adopted for SoCal is set forth in Appendix G, Table 5.

19. The core bundled rates and revenues and the noncore transport rates and revenues adopted for SoCal are set forth in Appendix G, Tables 6 and 7.

20. The 1989 Tracking Accounts Surcharge effective until January 14, 1991 adopted for SoCal is set forth in Appendix G, Table 8.

21. The gas demand and supply forecasts adopted for SDG&E are set forth in Appendix H.

22. The gas costs and revenue requirements adopted for SDG&E are set forth in Appendix I.

23. The core customer cost allocation, the noncore customer cost allocation, and the noncore transport rates and revenues adopted for SDG&E are set forth in Appendix J, Tables 1, 2, and 3.

24. The core bundled rates and revenues adopted for SDG&E are set forth in Appendix J, Table 4.

25. The LIRA rates and surcharge adopted for SDG&E are set forth in Appendix J, Table 5.

26. Schedule GL-1 rates (Roadrunner Club rates) adopted for SDG&E are set forth in Appendix J, Table 6.

O R D E R

IT IS ORDERED that:

1. Southern California Gas Company shall file, in accordance with General Order 96-A, tariff changes which implement the rate changes adopted in this proceeding and which are shown in Appendix C, using the revenue requirement shown in Appendix F.

2. San Diego Gas & Electric Company shall file, in accordance with General Order 96-A, tariff changes which implement the rate changes adopted in this proceeding and which are shown in Appendix D, using the revenue requirement shown in Appendix I.

3. The revised tariff schedules shall be filed on or after the effective date of this decision and at least 3 days prior to their effective date.

4. A.90-03-018 remains open to consider the rate design proposal of Long Beach at a time and place to be set by the presiding administrative law judge.

This order is effective today.

Dated November 9, 1990, at San Francisco, California.

G. MITCHELL WILK
President
FREDERICK R. DUDA
JOHN B. OHANIAN
PATRICIA M. ECKERT
Commissioners

Commissioner Stanley W. Hulett, being necessarily absent, did not participate.

I will file a written concurring opinion.
/s/ FREDERICK R. DUDA
Commissioner

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

Neal J. Shulman
NEAL J. SHULMAN, Executive Director
pb

APPENDIX A
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List of Appearances

Applicants: Glen J. Sullivan and Mark A. Minich, Attorneys at Law, and Earl K. Takemura, for Southern California Gas Company; and Barton M. Myerson, Attorney at Law, Keith Melville, and Beth A. Bowman, for San Diego Gas & Electric Company.

Interested Parties: Barkovich and Yap, by Barbara R. Barkovich, for California Large Energy Consumer Association; Crossborder Services, by Tom Beach, for Alberta Petroleum Marketing Commission; Richard K. Durant, Frank J. Cooley, and Robert S. Robinson, Attorneys at Law, for Southern California Edison Company; Michel Peter Florio and Joel R. Singer, Attorneys at Law, for Toward Utility Rate Normalization (TURN); Biddle & Hamilton, by Richard L. Hamilton, Attorney at Law, for Western Mobilehome Association, Wright & Co., and Roadrunner Club Association, Inc.; Steven M. Harris, for Transwestern Pipeline Company; R. W. Beck & Associates, by David Helsby, for R. W. Beck & Associates; Michael Hopkins, for the City of Glendale; Adrian Hudson, for California Gas Producers Association; Lindsay, Hart, Neil & Weigler, by Paul Kaufman, Attorney at Law, for Cogenerators of Southern California; Squire, Sanders & Dempsey, by Keith R. McCrea and Michael Mishkin, Attorneys at Law, for California Industrial Group, California League of Food Processors, and California Manufacturers Association; Preston A. Mike, Attorney at Law, for City of Los Angeles; Leamon W. Murphy, for Imperial Irrigation District; Jeff Nahigian, for JBS Energy, Inc.; O'Rourke & Company, by Thomas J. O'Rourke, for Southwest Gas Corporation; Roger J. Peters, and Mark R. Huffman, Attorneys at Law, for Pacific Gas and Electric Company; Robert L. Pettinato, for Los Angeles Department of Water & Power; David Plumb, for the City of Pasadena; Patrick J. Power and Carol Shaw, Attorneys at Law, for the City of Long Beach; John D. Quinley, for Cogeneration Service Bureau; Sheldon Reid, for North Canadian Oils; Jones, Day, Reavis & Pogue, by Michael E. Reznick, Attorney at Law, for Southern California Utility Power Pool; Jim Ross, for RCS, Inc.; Andrew Safir, for Recon Research; Armour, Goodin, Schlotz & MacBride, by James D. Squeri, Attorney at Law, for EOR Producers and Kelco Division of Merck & Company; Ronald M. Stassi, for the City of Burbank; Randolph L. Wu, Richard O. Baish, Phillip D. Erdom, Attorneys at Law, for El Paso Natural Gas Company; Morrison & Foerster, by Jerry Bloom, and Lynn Haug, Attorneys at Law, for California Cogeneration Council; Greve, Clifford, Diepenbrock & Paras, by Matthew V.

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Brady, Attorney at Law, and Grueneich & Ellison, by Christopher T. Ellison, Attorney at Law, for California Department of General Services; Karen Edson, for KKE & Associates; Lynn Newcomer, for SunPacific Energy; William Shaffran and William Pettingill, Attorneys at Law, for City of San Diego; Thomas A. Tribble, Attorney at Law, for Regents of the University of California; Morse, Richard, Weisenmiller & Associates, Inc., by Dr. Robert B. Weisenmiller, for Morse, Richard, Weisenmiller & Associates, Inc.; Michael Alcantar, Attorney at Law, and Bakaret & Chamberlin, by Michael Pretto, for themselves.

Division of Ratepayer Advocates: Kathleen C. Maloney, John S. Wong, Attorneys at Law, James Boothe and Faline Fua.

Commission Advisory and Compliance Division: Angela Minkin and Ramesh Ramchandani.

(END OF APPENDIX A)

APPENDIX B
Page 1

UNIFORM DISCOUNT ADJUSTMENT METHODOLOGY AND STREAMLINING THE LOGIC FLOW FOR USE IN ANNUAL COST ALLOCATION PROCEEDINGS

PURPOSE

Pursuant to Ordering Paragraph No. 3 of D.90-04-021, CACD convened a workshop on May 21, 1990. The purpose of the workshop was to develop a uniform discount adjustment (DA) methodology and a streamlined flow of logic for use in Annual Cost Allocation (ACAP) proceedings.

SUMMARY AND RECOMMENDATION

D.90-04-021 directed CACD to make a compliance filing setting forth the DA method and logic flow to be used as a base case in future ACAP filings, should consensus not be reached at the workshop. Although the participants were able to agree on the logic flow and the general workings of the DA, they were unable to reach consensus on the particulars of econometric forecasting or the discount adjustment methodology. Parties did agree that the discount adjustment is a negative number; i.e., a reduction in actual expected throughput for purposes of cost allocation. CACD recommends that all gas utilities be required to include the described base case here in their ACAP filings. CACD's recommendation is a modification of the DA methodology proposed by Southern California Gas Company (SoCal) and supported by TURN and DRA.

CACD also recommends that PG&E's proposal to incorporate one-day informational meetings into each ACAP schedule be adopted. These meetings should be scheduled at the pre-hearing conference and would be limited to gas and alternative fuel price forecasts, interutility throughput forecasts, and other issues as requested by the ALJ. The meetings will be informal and will therefore not require CACD's presence. CACD believes that such meetings would be useful in clarifying the issues and may shorten hearing time. All interested parties should therefore be encouraged to attend.

DISCUSSION

All participants, except SDG&E, agreed that regardless of the particular econometric forecasting models used in the ACAPs, the throughput forecast should be computed at discounted rates. PG&E uses an average rate in both the forecast and discount adjustment models. SoCal, DRA, and TURN agreed that the floor rate should be used as the fuel-switching variable. SoCal proposed that the floor rate be defined as the lowest rate at which gas is expected be sold. DRA noted that if curtailment is an issue, the floor rate should be no lower than the average UEG rate. If curtailment and discounting were to occur below the average UEG rate, the utility would lose revenue.

The SoCal/TURN method calculates econometric throughput forecasts at the floor rate and then moves up the demand curve, using price elasticity to determine demand at price increments up to the default rate. PG&E engaged a consultant who stated that the SoCal/TURN method assumes an aggregate demand function, overstates throughput and revenue, and therefore understates discounting. PG&E's proposed method appears to be theoretically more accurate since customers are grouped by their alternative fuel options, but also requires the use of more data, namely exit costs and gas premium.

In PG&E's opinion, SoCal's market doesn't require as much discounting because SoCal's market characteristics are quite different in that the default rates are lower and stringent air quality standards in Southern California reduce the likelihood of fuel-switching. These points are valid; however, PG&E has not demonstrated the magnitude of difference between its presumably more accurate approach and SoCal/TURN's approach. A uniform base case methodology for all gas utilities will undoubtedly aid in simplifying the ACAPs. PG&E and all other parties should also note that they do have the option to use alternate methodologies in addition to the base case methodology defined below.

BASE CASE METHODOLOGY

The following steps describe CACD's recommended base case methodology. The ACAP filings shold be submitted on a single integrated spreadsheet.

1. The floor rate is defined as the lowest rate at which gas is expected to be sold during the forecast period, but should not drop below the expected average UEG rate during periods of capacity curtailment.

2. Econometric and non-econometric throughputs, forecasted at the floor rate, will be used as proxies for actual throughput.

3. A seed default transportation rate is assumed. The spot gas price is appropriate for the commodity cost of gas on SoCal's system because there is very little core-election. When the core-elect price is less than the noncore spot price (as on PG&E's system), the lower of the forecasted spot or core-elect gas price should be used as the commodity price of gas.

4. Demand at each price interval from the floor rate to the default rate is calculated.

5. Each price change will be in successive 1 cent/therm steps. If the remainder is less than one-half

cent/therm, it should be combined with the previous step. Otherwise, an additional step should be used.

6. Revenue from the default rate customers is calculated by multiplying the computed default rate demand by the default rate.

7. Incremental revenue from each price decrement is calculated by multiplying the incremental demand by the lower rate.

8. Target revenue is the total of revenue at the default rate plus incremental revenues.

9. The discount adjustment factor is computed as follows:

Target Revenue/(Default Rate x Floor Rate Forecast Volume)

10. The forecasted throughput (at floor rates) is then multiplied by the discount adjustment factor to develop the "hypothetical" throughput at default rates, which is used for cost allocation purposes.

11. The cost allocation process will in turn generate a default rate which is used to recompute demand as stated in step 4 of the model.

12. Iteration: Steps 4 thru 11 are repeated until a stable default rate is reached.

ATTACHMENT 1

EXAMPLE OF ADOPTED DISCOUNT ADJUSTMENT CALCULATION

Assumptions:

Forecasted spot price of gas: 25.0 cents/therm (see footnote a/)
Stable default rate: 10.1 cents/therm
Floor rate: 5.0 cents/therm
Forecasted alternate fuel price: 29.6 cents/therm equivalent
Forecast volume (including discounts): 85,132 MDth

Because the forecast throughput includes discounts, the demands at higher prices are determined using price elasticity. The price elasticity used in this example is a weighted average of the elasticities in the industrial, commercial, and special customer sectors.

Calculations:

Rate c/therm	Elasticity	Margin c/therm	Demand MDth	Incremental Revenue ($M)
35.1	0.46	10.1	79,538	$80,333
34.1	0.46	9.1	80,580	949
33.1	0.46	8.1	81,667	880
32.1	0.42	7.1	82,802	661
31.1	0.42	6.1	83,886	623
30.0		5.0	85,132	623
			Target Revenue	$84,252
			Forecast volume x Default Rate	85,983

Discount Adjustment Factor:
= Expected Revenue/(Default Rate x Forecast Volume)
= 84,252/85,983 = 98.0%.

The discount adjustment factor is then applied to the forecasted throughput to determine hypothetical throughput for cost allocation purposes.

= 85,132 MDth x 98.0% = 83,418 MDth.

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a/ When the core-elect price is less than the noncore spot price, the lower price should be used as the commodity cost of gas.

(END OF APPENDIX B)

A.90-03-018 *
11/8/90

APPENDIX C

SOUTHERN CALIFORNIA GAS COMPANY
Summary of Revenue and Non-Gas Revenue Changes
Forecast Period: October 1, 1990 to September 30, 1991
(000's of $)

	Revenue at Present Rates	Revenue at Proposed Rates	Increase (Decrease)	Percent Change
Core				
Residential	1,646,224.2	1,735,922.6	89,698.3	5.45%
Other core (excluding UEG Igniter Fuel)	625,335.2	661,805.8	36,470.6	5.83%
Transport	4,771.2	5,624.0	852.8	17.87%
Core Total	2,276,330.7	2,403,352.4	127,021.7	5.58%
	Non-gas Revenue at Present Rates	**Non-gas Revenue at Proposed Rates**	**Increase (Decrease)**	**Percent Change**
Noncore				
Industrial	87,580.1	79,446.1	(8,134.0)	-9.29%
Cogeneration	40,114.2	32,361.3	(7,752.9)	-19.33%
UEG	140,544.5	110,048.4	(30,496.0)	-21.70%
Long-term contracts	4,678.0	4,801.9	123.9	2.65%
Subtotal	272,916.8	226,657.8	(46,259.0)	-16.95%
Wholesale				
Long Beach	21,084.6	17,595.8	(3,488.8)	-16.55%
SDG&E	95,683.0	84,256.6	(11,426.4)	-11.94%
Subtotal	116,767.6	101,852.4	(14,915.2)	-12.77%
Noncore Total	382,766.9	328,510.2	(54,256.8)	-14.17%
System Total 1/	2,659,097.6	2,731,862.5	72,764.9	2.74%

1/ Core bundled revenue and noncore transmission revenue

(END OF APPENDIX C)

APPENDIX D

08-Nov-90

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1990 to September 30, 1991

TABLE 1

ADOPTED REVENUE CHANGES

($000)

Core	Revenue at Present Rates	Revenues at Proposed Rates	Increase/ Decrease	Percent Change
Residential	201,845.2	185,669.6	(16,175.7)	-8.01%
Commercial	65,515.8	63,130.6	(2,385.2)	-3.64%
Transport	1,311.9	1,072.4	(239.6)	-18.26%
Core Total	268,673.0	249,872.6	(18,800.4)	-7.00%
Noncore	**Nongas Revenues at Present Rates**	**Nongas Revenues at Proposed Rates**	**Increase/ Decrease**	**Percent Change**
Industrial	10,416.4	9,669.3	(747.1)	-7.17%
Cogeneration	18,155.0	16,345.9	(1,809.1)	-9.96%
UEG	35,836.0	40,050.1	4,214.0	11.76%
Noncore Total	64,407.5	66,065.2	1,657.8	2.57%
Total	333,080.5	315,937.8	(17,142.6)	-5.15%

(END OF APPENDIX D)

APPENDIX E

TABLE 1

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED GAS DEMAND & DELIVERIES

Forecast Period: October 1, 1990 to September 30, 1991

THROUGHPUT TYPE	GAS DEMAND (Mdth)	
Residential	285,217.0	
Commercial Core	74,148.0	
Commercial Non-Core	17,096.0	
Industrial Core	35,801.6	
Industrial Non-Core	70,781.1	
Retail UEG	204,938.0	
Commercial Cogeneration	20,765.0	
Industrial Cogeneration	49,747.9	
EOR Cogeneration	124,627.0	
EOR Steamflood	63,187.0	
Company use	7,150.3	
Unaccounted for	11,286.4	
Storage surface losses	121.0	
Long Beach - wholesale	29,385.3	
San Diego - wholesale	113,691.7	
Total Sales and Transport	1,107,943.4	Mdth
Exchange	31,983.0	
Interutility transport	7,481.0	
TOTAL GAS DEMAND	1,147,407.4	Mdth
California supplies	90,657.0	
Out-of-state supplies	984,701.4	
Supplies from PG&E	57,260.7	
Net storage change	(20,733.1)	
AVAILABLE SUPPLIES	1,111,886.0	Mdth
AVERAGE YEAR CURTAILMENTS	35,521.4	Mdth

TABLE 2

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED DEMAND AND SUPPLY FORECASTS by CUSTOMER CLASS

Forecast Period: October 1, 1990 to September 30, 1991

SCHEDULE AND CATEGORY		PRIO-RITY	DEMAND FORECAST (Mdth)	CURT-AILMENT (Mdth)	SUPPLY FORECAST (Mdth)
Residential			285,217.0		285,217.0
Commercial	GN-10C	P-1	68,259.0		68,259.0
Commercial	GN-20C	P-2A	5,447.4		5,447.4
Commercial	GN-20N	P-2A	244.6		244.6
Commercial	GN-20T	P-2A	197.0		197.0
Commercial	GN-30N	P-2B	1,420.0		1,420.0
Commercial	GN-30T	P-2B	77.0		77.0
Commercial	GN-10C	P-3A	331.0		331.0
Commercial	GN-20C	P-3A	107.0		107.0
Commercial	GN-20N	P-3A	59.9		59.9
Commercial	GN-30N	P-3A	1,621.9		1,621.9
Commercial	GN-50N	P-3A	4,640.2		4,640.2
Commercial	GN-30T	P-3A	167.0		167.0
Commercial	GN-50T	P-3A	10,093.0		10,093.0
Commercial	GN-50T(L)	P-3A	3,745.0		3,745.0
Commercial	GN-30E	P-3B	840.0		840.0
Commercial	GN-30N	P-3B	9,412.0		9,412.0
Commercial	GN-30T	P-3B	1,008.0		1,008.0
Commercial	GN-30E	P-4	528.0		528.0
Commercial	GN-30N	P-4	2,627.0		2,627.0
Commercial	GN-30T	P-4	1,184.0		1,184.0
Total Commercial			112,009.0	0.0	112,009.0
Industrial	GN-10C	P-1	21,012.0		21,012.0
Industrial	GN-20C	P-2A	12,397.9		12,397.9
Industrial	GN-20N	P-2A	733.7		733.7
Industrial	GN-20T	P-2A	1,521.0		1,521.0
Industrial	GN-20C	P-2B	110.0		110.0
Industrial	GN-20T	P-2B	26.9		26.9
Industrial	GN-30E	P-2B	120.0		120.0
Industrial	GN-30N	P-2B	8,261.0		8,261.0
Industrial	GN-30T	P-2B	7,092.1		7,092.1
Industrial	GN-30T(L)	P-2B	172.0		172.0
Industrial	GN-10C	P-3A	34.0		34.0
Industrial	GN-20N	P-3A	0.0		0.0
Industrial	GN-30E	P-3A	24.0		24.0
Industrial	GN-30N	P-3A	494.6		494.[illegible]
Industrial	GN-50N	P-3A	1,933.4		1,933.4
Industrial	GN-30T	P-3A	2,064.0		2,064.0
Industrial	GN-50T	P-3A	6,814.9		6,814.9
Industrial	GN-50T(L)	P-3A	38,383.0		38,383.0

TABLE 2 (cont'd)

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED DEMAND AND SUPPLY FORECASTS by CUSTOMER CLASS

Forecast Period: October 1, 1990 to September 30, 1991

SCHEDULE AND CATEGORY		PRIORITY	DEMAND FORECAST (Mdth)	CURTAILMENT (Mdth)	SUPPLY FORECAST (Mdth)
EOR Cogen	GN-40N	P-3A	0.0		0.0
EOR Cogen	GN-40T	P-3A	1,695.0		1,695.0
EOR Cogen	GN-40T(L)	P-3A	122,932.0		122,932.0
Industrial	GN-30E	P-3B	672.0		672.0
Industrial	GN-30N	P-3B	20,821.0		20,821.0
Industrial	GN-30T	P-3B	22,824.0		22,824.0
Industrial	GN-30T(L)	P-3B	2,278.0		2,278.0
Industrial	GN-30N	P-4	2,725.0		2,725.0
Industrial	GN-30T	P-4	5,534.0		5,534.0
Industrial	GN-30T(L)	P-4	282.0		282.0
EOR Steam	GN-40N	P-5	1,079.0	(155.7)	923.3
EOR Steam	GN-40T	P-5	21,246.0	(3,065.7)	18,180.3
EOR Steam	GN-40T(L)	P-5	40,862.0	(5,896.2)	34,965.8
Total Industrial			344,144.6	(9,117.6)	335,027.0
UEG sales	GN-60C	P-2A	2,335.0		2,335.0
UEG Noncore	GN-60N	P-2C&	7,056.0		7,056.0
UEG S-Term	GN-60T	P-2C&	39,996.0		39,996.0
UEG Noncore	GN-60N	P-5	109,511.0	(15,802.0)	93,709.0
UEG S-Term	GN-60T	P-5	46,040.0	(6,643.4)	39,396.6
Total UEG			204,938.0	(22,445.3)	182,492.7
Exchange w/other util		P-1	2,835.0		2,835.0
Onshore Cal. exch.		P-1	418.0		418.0
Offshore P.Point exch		P-1	309.0		309.0
Onshore Cal. exch.		P-2A	859.0		859.0
Offshore P.Point exch		P-2A	851.0		851.0
Onshore Cal. exch.		P-2B	1,105.0		1,105.0
Offshore P.Point exch		P-2B	576.0		576.0
Onshore Cal. exch.		P-3A	5,885.0		5,885.0
Offshore P.Point exch		P-3A	8,050.0		8,050.0
Onshore Cal. exch.		P-3B	3,668.0		3,668.0
Offshore Cal. exch.		P-3B	237.0		237.0
Offshore P.Point exch		P-3B	1,233.0		1,233.0
Onshore Cal. exch.		P-4	780.0		780.0
Offshore P.Point exch		P-4	160.0		160.0
Onshore Cal. exch.		P-5	705.0	(101.7)	603.3
Offshore P.Point exch		P-5	4,312.0	(622.2)	3,689.8
Total Exchange			31,983.0	(723.9)	31,259.1

TABLE 2 (cont'd)

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED DEMAND AND SUPPLY FORECASTS by CUSTOMER CLASS

Forecast Period: October 1, 1990 to September 30, 1991

SCHEDULE AND CATEGORY	PRIOR-ITY	DEMAND FORECAST (Mdth)	CURT-AILMENT (Mdth)	SUPPLY FORECAST (Mdth)
Fuel use - injection	P-1	693.0	(56.3)	636.7
Fuel use - mainline	P-1	5,786.1	(177.7)	5,608.4
Misc. company use	P-1	599.7	(20.3)	579.4
Misc. company use	P-2A	71.5	(2.3)	69.3
Total company use		7,150.3	(256.7)	6,893.7
Unaccounted for	P-1	11,286.4	(346.7)	10,939.7
Stor. Surface Loss	P-1	121.0	0.0	121.0
TOTAL RETAIL		996,849.3	(32,890.2)	963,959.1
LBeach sales S-T TRN	P-1	10,932.0		10,932.0
LBeach co use S-T TRN	P-1	12.3	(0.9)	11.4
LBeach unacct S-T TRN	P-1	340.0	(24.6)	315.4
Less: own supply	P-1	4,775.0		4,775.0
LBeach sales S-T TRN	P-2A	688.6		688.6
LBeach S-T TRN	P-2B	56.0		56.0
LBeach UEG S-T	P-3	3,298.0		3,298.0
LBeach S-T TRN	P-3A	19.6		19.6
LBeach reg S-T TRN	P-3B	3,177.1		3,177.1
LBeach S-T TRN	P-4	1,099.7		1,099.7
LBeach UEG S-T	P-5	14,537.0	(2,097.6)	12,439.4
Total Long Beach		29,385.3	(2,123.1)	27,262.2
SDG&E Residential	P-1	33,426.1		33,426.1
SDG&E Co Use S-T TRN	P-1	299.5	0.0	299.5
SDG&E Unacct S-T TRN	P-1	780.9	0.0	780.9
SDG&E Commercial	P1&2A	11,459.9		11,459.9
SDG&E IGN S-T TRN	P-2A	254.0		254.0
SDG&E Industrial	P-2B&3B&4	5,540.3		5,540.3
SDG&E Cogeneration	P-3A	19,220.0		19,220.0
SDG&E UEG	P-3	7,881.0		7,881.0
SDG&E Steam	P-4	111.0		111.0
SDG&E UEG	P-3AA	33,626.7		33,626.7
SDG&E UEG	P-5	1,092.3	0.0	1,092.3
Total San Diego		113,691.7	0.0	113,691.7
TOTAL WHOLESALE		143,077.1	(2,123.1)	140,954.0
INTERUTILITY	P-3A	3,960.0		3,960.0
	P-5	3,521.0	(508.1)	3,012.9
TOTAL		1,147,407.4	(35,521.4)	1,111,886.0

TABLE 3

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED DEMAND AND SUPPLY FORECASTS by CUSTOMER CLASS

Forecast Period: October 1, 1990 to September 30, 1991

PRIORITY	DEMAND FORECAST (Mdth)	CURT-AILMENT (Mdth)	SUPPLY FORECAST (Mdth)
P-1	447,923.3	(626.5)	447,296.8
P-2A	26,435.5	(2.3)	26,687.2
P-2B	20,544.3	0.0	20,290.3
P-2C	11,760.1	0.0	11,760.1
P-3	46,470.9	0.0	46,470.9
P-3AA	33,626.7	0.0	33,626.7
P-3A	232,274.5	0.0	232,274.5
P-3B	70,436.1	0.0	70,436.1
P-4	15,030.7	0.0	15,030.7
P-5	242,905.3	(34,892.6)	208,012.7
TOTAL	1,147,407.4	(35,521.4)	1,111,886.0

Note: P-1 and P-2A curtailments reflect the reduction in "company use and unaccounted for" gas as a consequence of adopted P-5 curtailments.

TABLE 4

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED SUPPLY FORECAST by PORTFOLIO CLASS

Forecast Period: October 1, 1990 to September 30, 1991

		PRIORITY	SUPPLY FORECAST (Mdth)	
CORE & CORE-ELECT PORTFOLIO				
Residential				285,217.0
Commercial	GN-10C	P-1	68,259.0	
Industrial	GN-10C	P-1	21,012.0	
Non-Residential				89,271.0
Commercial	GN-20C	P-2A	5,447.4	
Industrial	GN-20C	P-2A	12,397.9	
Industrial	GN-20C	P-2B	110.0	
Commercial	GN-10C	P-3A	331.0	
Commercial	GN-20C	P-3A	107.0	
Industrial	GN-10C	P-3A	34.0	
Non-Residential				18,427.3
Industrial	GN-30E	P-3B	672.0	
Commercial	GN-30E	P-3B	840.0	
Commercial	GN-30E	P-4	528.0	
Industrial	GN-30E	P-2B	120.0	
Industrial	GN-30E	P-3A	24.0	
Regular Commercial & Industrial				2,184.0
UEG sales	GN-60C	P-2A	2,335.0	
Retail UEG				2,335.0
Subtotal				397,434.3
Company use				2,796.7
Unaccounted for				4,438.2
Stor. Surface Loss				49.1
TOTAL CORE & CORE-ELECT PORTFOLIO				404,718.4
NON-CORE PORTFOLIO				
Commercial	GN-30N	P-2B	1,420.0	
Commercial	GN-20N	P-2A	244.6	
Commercial	GN-20N	P-3A	59.9	
Industrial	GN-20N	P-2A	733.7	

TABLE 4 (cont'd)

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED SUPPLY FORECAST by PORTFOLIO CLASS

Forecast Period: October 1, 1990 to September 30, 1991

		PRIORITY	SUPPLY FORECAST (Mdth)	
Industrial	GN-30N	P-2B	8,261.0	
Commercial	GN-30N	P-3A	1,621.9	
Commercial	GN-30N	P-3B	9,412.0	
Industrial	GN-30N	P-3B	20,821.0	
Commercial	GN-30N	P-4	2,627.0	
Industrial	GN-30N	P-4	2,725.0	
Industrial	GN-30N	P-3A	494.6	
Industrial	GN-20N	P-3A	0.0	
Regular Commercial & Industrial				48,420.7
UEG Noncore	GN-60N	P-2C&3	7,056.0	
UEG Noncore	GN-60N	P-5	93,709.0	
Retail UEG				100,765.0
Commercial	GN-50N	P-3A	4,640.2	
Industrial	GN-50N	P-3A	1,933.4	
Regular Cogeneration				6,573.6
EOR Cogen	GN-40N	P-3A		0.0
EOR Steam	GN-40N	P-5		923.3
Subtotal				156,682.7
Company use				1,102.6
Unaccounted for				1,749.7
Stor. Surface Loss				19.4
TOTAL NON-CORE PORTFOLIO				159,554.3
SHORT-TERM TRANSPORT				
Commercial	GN-20T	P-2A	197.0	
Industrial	GN-20T	P-2A	1,521.0	
Industrial	GN-20T	P-2B	26.9	
Non-Residential				1,744.9
Industrial	GN-30T	P-2B	7,092.1	
Commercial	GN-30T	P-2B	77.0	
Commercial	GN-30T	P-3A	167.0	
Industrial	GN-30T	P-3A	2,064.0	
Commercial	GN-30T	P-3B	1,008.0	

TABLE 4 (cont'd)

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED SUPPLY FORECAST by PORTFOLIO CLASS

Forecast Period: October 1, 1990 to September 30, 1991

PRIORITY			SUPPLY FORECAST (Mdth)	
Industrial	GN-30T	P-3B	22,824.0	
Commercial	GN-30T	P-4	1,184.0	
Industrial	GN-30T	P-4	5,534.0	
Regular Commercial & Industrial				39,950.1
UEG S-Term	GN-60T	P-2C&3	39,996.0	
UEG S-Term	GN-60T	P-5	39,396.6	
Retail UEG				79,392.6
Commercial	GN-50T	P-3A	10,093.0	
Industrial	GN-50T	P-3A	6,814.9	
Regular Cogeneration				16,907.9
EOR Cogen	GN-40N	P-3A		1,695.0
EOR Steam	GN-40N	P-5		18,180.3
Subtotal				157,870.8
Company use				1,110.9
Unaccounted for				1,763.0
Stor. Surface Loss				19.5
SDG&E Commercial		P1&2A	11,459.9	
SDG&E UEG		P-3	7,881.0	
SDG&E UEG		P-5	1,092.3	
SDG&E Wholesale UEG				20,433.2
SDG&E Residential		P-1	33,426.1	
SDG&E IGN S-T TRN		P-2A	254.0	
SDG&E Industrial P-2B,		&3B&4	5,540.3	
SDG&E Cogeneration		P-3A	19,220.0	
SDG&E Steam		P-4	111.0	
SDG&E Wholesale NON-UEG				58,551.4
SDG&E Co Use S-T TRN		P-1	299.5	
SDG&E Unacct S-T TRN		P-1	780.9	
SDG&E Company Use & Unaccounted For				1,080.4
LBeach UEG S-T		P-3	3,298.0	
LBeach UEG S-T		P-5	12,439.4	
Long Beach Wholesale UEG				15,737.4
LBeach sales S-T TRN		P-1	10,932.0	
Less: own supply		P-1	4,775.0	

TABLE 4 (cont'd)

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED SUPPLY FORECAST by PORTFOLIO CLASS

Forecast Period: October 1, 1990 to September 30, 1991

	PRIORITY		SUPPLY FORECAST (Mdth)
LBeach sales S-T TRN	P-2A	688.6	
LBeach S-T TRN	P-2B	56.0	
LBeach S-T TRN	P-3A	19.6	
LBeach reg S-T TRN	P-3B	3,177.1	
LBeach S-T TRN	P-4	1,099.7	
Long Beach Wholesale NON-UEG			11,198.0
LBeach co use S-T TRN	P-1	11.4	
LBeach unacct S-T TRN	P-1	315.4	
Long Beach company use & unaccounted for			326.9
TOTAL SHORT-TERM TRANSPORT			268,091.5
LONG-TERM TRANSPORT			
Industrial GN-30T(L)	P-2B	172.0	
Industrial GN-30T(L)	P-3B	2,278.0	
Industrial GN-30T(L)	P-4	282.0	
Regular Commercial & Industrial			2,732.0
Commercial GN-50T(L)	P-3A	3,745.0	
Industrial GN-50T(L)	P-3A	38,383.0	
Regular Cogeneration			42,128.0
EOR Cogen GN-40N	P-3A		122,932.0
EOR Steam GN-40N	P-5		34,965.8
SDG&E UEG	P-3AA		33,626.7
Subtotal			236,384.5
Company use			1,663.4
Unaccounted for			2,639.8
Stor. Surface Loss			29.2
TOTAL LONG-TERM TRANSPORT			240,716.9

TABLE 4 (cont'd)

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED SUPPLY FORECAST by PORTFOLIO CLASS

Forecast Period: October 1, 1990 to September 30, 1991

PRIORITY		SUPPLY FORECAST (Mdth)	
EXCHANGE			
Exchange w/other util	P-1	2,835.0	
Onshore Cal. exch.	P-1	418.0	
Offshore P.Point exch	P-1	309.0	
Non-Residential			3,562.0
Onshore Cal. exch.	P-2A	859.0	
Offshore P.Point exch	P-2A	851.0	
Non-Residential			1,710.0
Onshore Cal. exch.	P-2B	1,105.0	
Offshore P.Point exch	P-2B	576.0	
Onshore Cal. exch.	P-3B	3,668.0	
Offshore Cal. exch.	P-3B	237.0	
Offshore P.Point exch	P-3B	1,233.0	
Onshore Cal. exch.	P-4	780.0	
Offshore P.Point exch	P-4	160.0	
Regular Commercial & Industrial			7,759.0
Onshore Cal. exch.	P-3A	5,885.0	
Offshore P.Point exch	P-3A	8,050.0	
Regular and EOR cogeneration			13,935.0
Onshore Cal. exch.	P-5	603.3	
Offshore P.Point exch	P-5	3,689.8	
EOR Steam GN-40N			4,293.1
Subtotal			31,259.1
Company use			220.0
Unaccounted for			349.1
Stor. Surface Loss			3.9
TOTAL EXCHANGE			31,832.0
INTERUTILITY TRANSPORT	P-3A		3,960.0
	P-5		3,012.9
TOTAL SUPPLY FORECAST			1,111,886.0

TABLE 5

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED COSTS

Forecast Period: October 1, 1990 to September 30, 1991

	VOLUMES (Mdth)	PRICE ($/dth)	COSTS (000's of $)	
Core & Core-Elect Supplies				
Elk Hills	0	2.5398	0.0	
Misc. California purchases	40,027	2.6389	105,628.7	
Direct purchases - SW USA	243,892	2.5837	630,143.8	
POPCO - Hondo Tiers 1 & 2	13,027	2.5928	33,776.4	
PITCO - Pan Alberta Tier 1	50,126	2.4200	121,304.4	
PITCO - Pan Alberta Tier 2	32,360	2.4200	78,311.7	
Federal Offshore	4,518	4.0261	18,189.9	
Core to Non-core Adj.	0	2.5398	0.0	
Short-term purchases	20,756	2.5000	51,891.0	
MPO Transition Cost Adj.			(11,373.8)	
Adj. Core/Core-elect purcha	404,706			1,027,872.1
Core & Core-elect WACOG		2.5398		
Core Storage				
Storage Withdrawl	60,073	2.5398	152,573.2	
Storage Injection	(60,061)	2.5398	(152,542.7)	
Net storage	12			30.5
Non-Core Supplies				
Non-core purchases & WACOG	159,554	2.5395		405,184.4
Pipeline Demand Charges (fixed)				
El Paso			74,315.0	
Transwestern			73,659.0	
PITCO - Pan Alberta			102,300.0	
POPCO - Hondo			37,996.0	288,270.0
PIOC - Pitas Point	15,108			36,108.0

TABLE 5 (cont'd)

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED COSTS

Forecast Period: October 1, 1990 to September 30, 1991

		VOLUMES (Mdth)	PRICE ($/dth)	COSTS (000's of $)	
Transition costs					
Direct bills:					
El Paso Liquids				0.0	
Take-or-Pay				63,400.0	
FERC Account 191				33,518.4	
Southland/Chevron	Memo:		45,081.6	(33,518.4)	
Subtotal				63,400.0	
MPO Transition Cost Adj.				11,373.8	
Excess Purch. Gas Costs (carried over from 1988)				2,994.0	77,767.8
Balancing/Tracking accounts: Updated for 7/31/90 recorded balances					
Core Purchased Gas Account (CPGA)					
Core:				105,043.5	
Core-elect				505.5	
					105,549.0
Other Core accounts:					
Core Fixed Cost Account (CFCA)				121,297.0	
Core Implementation Account (CIA)				(77,480.0)	
Conservation Cost Adjustment (CCA)				(40,875.0)	
Enhanced Oil Recovery Account (EORA)				(23,968.0)	(21,026.0)
Non-Core accounts:					
Negotiated Revenue Stability Account (NRSA)				(8,087.0)	
Enhanced Oil Recovery Account (EORA)				(7,533.0)	
Noncore Implementation Account (NIA)				(73,245.0)	
Minimum Purchase Obligation (MPO)				3,859.0	
Pipeline Demand Charges (PDC)				(5,643.0)	
Noncore Transition Cost Account (NTCA) 1/				0.0	
Cogeneration Shortfall Account (CSA)				0.0	
Carrying Cost of Storage				(1,052.0)	
Take-or-Pay				14,139.0	
Fixed Cost Acct. (NFCA) Marg. Shortfall 1/				0.0	
Conservation Cost Adjustment (CCA)				(9,199.0)	(86,761.0)

1/ NCTA and NFCA consolidated into the NIA.

TABLE 5 (cont'd)

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED COSTS

Forecast Period: October 1, 1990 to September 30, 1991

	VOLUMES (Mdth)	PRICE ($/dth)	COSTS (000's of $)	
Company use and Unaccounted for				
Core Company Use	2,846	2.5397	7,227.8	
Core Unaccounted For	4,516	2.5397	11,470.0	
Total	7,362			18,697.9
Non-core Company Use	4,048	2.5397	10,280.1	
Non-core Unaccounted For	6,423	2.5397	16,313.7	
Total	10,471			26,593.7

TABLE 6

SOUTHERN CALIFORNIA GAS COMPANY
ADOPTED PORTFOLIO PRICES

Forecast Period: October 1, 1990 to September 30, 1991

	VOLUMES (Mdth)	COSTS (000's of $)
Core & Core-elect Portfolio		
Adj. Core Purchases	404,706	1,027,872.1
Net storage	12	30.5
Core & Core-elect portfolio demand	404,718	1,027,902.5
Less: Company use & unaccounted for	7,284	18,499.4
Add: Core Purchased Gas Account (CPGA) 2/		105,043.5
Subtotal		1,114,446.7
Add: FF&U at 2.1076%		23,488.1
CORE & CORE-ELECT SALES	397,434	1,137,934.8
CORE & CORE-ELECT PORTFOLIO PRICE		$2.8632 /dth

2/ Does not include Core-Elect PGA ($505,500) which is amortized in monthly postings.

	VOLUMES (Mdth)	COSTS (000's of $)
Non-Core Portfolio		
Non-core porfolio demand	159,554	405,184.4
Less: Company use & unaccounted for	2,872	7,293.1
Add: Pitas Point		36,108.0
Subtotal		433,999.3
Add: FF&U at 2.1076%		9,147.0
Subtotal		443,146.3
Less: Pitas Point		36,108.0
NON-CORE PORTFOLIO SALES	156,683	407,038.3
NON-CORE PORTFOLIO PRICE ($/dth)		$2.5979 /dth

(END OF APPENDIX E)

A.90-03-018* APPENDIX F 11/8/90

SOUTHERN CALIFORNIA GAS COMPANY: ADOPTED REVENUE REQUIREMENTS
Forecast Period: October 1, 1990 to September 30, 1991
(000's of $)

PROCUREMENT REVENUE REQUIREMENT		
Total Core Procurement Revenue 1/	$1,137,934.8	
Total Non-core Procurement Revenue 1/	407,038.3	
TOTAL PROCUREMENT REVENUE REQUIREMENT		1,544,973.1
TRANSMISSION REVENUE REQUIREMENT		
Auth. gas margin (As adopted in D.90-01-016) less brokerage fees		
Common distribution	370,122.0	
Demand related transmission	113,828.0	
Demand related storage	98,490.0	
Customer related	648,682.0	
Commodity related	0.0	
50% Administrative & General	139,566.0	
		1,370,688.0
Pipeline demand charges	288,270.0	
Add: FF&U	5,893.3	
		294,163.3
Transition costs	77,767.8	
Add: FF&U	1,592.3	
		79,360.1
Women Minority Business Enterprises (WMBE)	249.0	
Mutual Assistance Agreement (MMA)	3,777.0	
Migration Losses	307.0	
Gas Loss Memo Account (GLMA)	264.0	
Carrying cost of storage	2,359.0	
Other Core Balancing/tracking accounts	(21,026.0)	
Non-Core Balancing/tracking accounts	(86,761.0)	
Add: FF&U	(2,125.3)	
		(102,956.3)
Core Company use and unaccounted for gas	18,697.9	
Non-Core Company use and unaccounted for gas	26,593.7	
Add: FF&U	931.1	
		46,222.7
Storage banking rev.: Pilot Program (ext. per D.90-10-038)		(1,621.6)
Exchange revenues		(8,431.0)
Interutility transportation revenues		(609.0)
TOTAL TRANSMISSION REVENUE REQUIREMENT		1,676,816.1
Brokerage Fees		3,960.0
LIRA Benefit		(20,500.7)
LIRA Surcharge		22,450.9
Net LIRA increase in revenue requirements		1,950.2
NET REVENUE REQUIREMENT 2/		$3,221,789.2
NET REVENUE REQUIREMENT (INCLUDING LIRA & BROKERAGE FEES)		$3,227,699.4

1/ Does not include Core-elect PGA which is amortized in monthly postings
2/ Revenue requirement used for cost allocation and rate design

(END OF APPENDIX F)

SOUTHERN CALIFORNIA GAS COMPANY
COST ALLOCATION SUMMARY

Forecast Period: October 1, 1990 to September 30, 1991

FORECAST PERIOD COSTS	CORE COST ($000)	NON-CORE COST ($000)	WHOLESALE COST ($000)	SYSTEM COST ($000)
TRANSPORTATION REVENUE REQUIREMENT				
Common distribution	331,707	38,415	0	370,122
Demand related transmission	55,918	39,424	18,486	113,828
Demand related storage	60,247	22,558	15,685	98,490
Customer related	636,983	7,996	3,703	648,682
Commodity related	0	0	0	0
50% Administrative & General	73,967	62,579	3,020	139,566
SUBTOTAL - Base (margin)	1,158,822	170,972	40,893	1,370,688
Net EOR Adjustment	(50,964)	54,425	(3,461)	(0)
Interutility transport rev.	(299)	(211)	(99)	(609)
Exchange revenues	(4,142)	(2,920)	(1,369)	(8,431)
Storage Banking Revenue	0	(931)	(690)	(1,622)
TOTAL - Adjusted Base	1,103,417	221,335	35,274	1,360,026
Pipeline demand charges	144,598	101,945	47,620	294,163
Co. use & unaccounted for (t/p)	17,436	22,635	6,151	46,223
Women Min. Bus. Ent. (WMBE)	116	98	41	254
Mutual Assist. Agree. Gas (MAA)	0	3,857	0	3,857
Carry Cost Storage Inv (CCSI)	1,473	552	382	2,407
Migration Losses	192	72	50	313
Gas Loss Memo Account (GLMA)	165	62	43	269
Transition costs				
Direct bills:	29,423	24,893	10,380	64,697
MPO Transition Cost Adj.	5,278	4,466	1,862	11,606
Excess Purch. Gas Costs (carried over from 1988)	0	3,057	0	3,057
TOTAL - Forecast Period Costs	1,302,099	382,971	101,803	1,786,873
AMORTIZATION OF BALANCING ACCOUNTS: INCLUDES ADJUSTMENT FOR BALANCING ACCOUNT CONSOLIDATION 1/				
Core Fixed Cost Account (CFCA)	123,853	0	0	123,853
Core Implementation Account (CIA)	(79,113)	0	0	(79,113)
Conservation Cost Adjustment (CCA)	(41,736)	0	0	(41,736)
Enhanced Oil Recovery Account (EORA)	(19,160)	(4,012)	(1,296)	(24,468)
Negotiated Revenue Stability Account (NRSA)	0	(5,821)	(2,427)	(8,248)
Enhanced Oil Recovery Account (EORA)	(6,022)	(1,261)	(407)	(7,690)
Noncore Implementation Account (NIA) 1/	0	(75,984)	0	(75,984)
Minimum Purchase Obligation (MPO)	0	2,778	1,158	3,936
Pipeline Demand Charges (PDC)	0	(3,923)	(1,832)	(5,755)
Noncore Transition Cost Account (NTCA) 1/	0	0	1,435	1,435
Cogeneration Shortfall Account (CSA)	0	0	0	0
Carrying Cost of Storage	0	(634)	(439)	(1,072)
Take-or-Pay	0	10,177	4,244	14,421
Fixed Cost Acct. (NFCA) Marg. Shortfall 1/	0	0	(242)	(242)
Conservation Cost Adjustment (CCA)	0	(9,393)	0	(9,393)
SUBTOTAL - Forecast Account Balances	(22,178)	(88,072)	193	(110,057)
TOTAL - Transportation Revenue Requirement	1,279,921	294,900	101,995	1,676,816
ALLOCATION ADJUSTMENTS				
Long-term contract shortfall	0	(4,960)	0	(4,960)
Long-term contract spread	2,293	1,855	812	4,960
CCSI Credit to wholesale	0	0	(955)	(955)
CCSI Whl. Credit Spread	695	260	0	955
TRANSPORTATION COSTS	1,282,908	292,055	101,852	1,676,816

1/ NCTA and NFCA adjustments to wholesale shown for informational purposes.
These adjustments were incorporated into rate design to consolidate the balancing accounts into the NIA.

SOUTHERN CALIFORNIA GAS COMPANY
CORE CUSTOMER COST ALLOCATION

Forecast Period: October 1, 1990 to September 30, 1991

FORECAST PERIOD COSTS	RESIDENTIAL ($000)	COMMERCIAL ($000)	TOTAL ($000)
TRANSPORTATION REVENUE REQUIREMENT			
Common distribution	259,376	72,331	331,707
Demand related transmission	40,902	15,016	55,918
Demand related storage	46,559	13,688	60,247
Customer related	587,425	49,558	636,983
Commodity related	0	0	0
50% Administrative & General	53,002	20,965	73,967
SUBTOTAL - Base (margin)	987,264	171,558	1,158,822
Net EOR Adjustment	(42,738)	(8,226)	(50,964)
Interutility transport rev.	(219)	(80)	(299)
Exchange revenues	(3,030)	(1,112)	(4,142)
Storage Banking Revenue	0	0	0
TOTAL - Adjusted Base	941,278	162,139	1,103,417
Pipeline demand charges	105,767	38,830	144,598
Co. use & unaccounted for (t/p)	12,494	4,942	17,436
Women Min. Bus. Ent. (WMBE)	83	33	116
Mutual Assist. Agree. Gas (MAA)	0	0	0
Carry Cost Storage Inv (CCSI)	1,139	335	1,473
Migration Losses	148	44	192
Gas Loss Memo Account (GLMA)	127	37	165
Transition costs			
Direct bills:	21,084	8,340	29,423
MPO Transition Cost Adj.	3,782	1,496	5,278
Excess Purch. Gas Costs (carried over from 1988)	0	0	0
TOTAL - Forecast Period Costs	1,085,903	216,196	1,302,099
AMORTIZATION OF BALANCING ACCOUNTS: INCLUDES ADJUSTMENT FOR BALANCING ACCOUNT CONSOLIDATION			
Core Fixed Cost Account (CFCA)	88,749	35,104	123,853
Core Implementation Account (CIA)	(56,690)	(22,423)	(79,113)
Conservation Cost Adjustment (CCA)	(29,907)	(11,830)	(41,736)
Enhanced Oil Recovery Account (EORA)	(16,067)	(3,093)	(19,160)
Negotiated Revenue Stability Account (NRSA)	0	0	0
Enhanced Oil Recovery Account (EORA)	(5,050)	(972)	(6,022)
Noncore Implementation Account (NIA)	0	0	0
Minimum Purchase Obligation (MPO)	0	0	0
Pipeline Demand Charges (PDC)	0	0	0
Noncore Transition Cost Account (NTCA)	0	0	0
Cogeneration Shortfall Account (CSA)	0	0	0
Carrying Cost of Storage	0	0	0
Take-or-Pay	0	0	0
Fixed Cost Acct. (NFCA) Marg. Shortfall 1/	0	0	0
Conservation Cost Adjustment (CCA)	0	0	0
SUBTOTAL - Forecast Account Balances	(18,965)	(3,213)	(22,178)
TOTAL - Transportation Revenue Requirement	1,066,938	212,983	1,279,921
ALLOCATION ADJUSTMENTS			
Long-term contract shortfall	0	0	0
Long-term contract spread	1,643	650	2,293
CCSI Credit to wholesale	0	0	0
CCSI Whl. Credit Spread	537	158	695
TRANSPORTATION COSTS	1,069,118	213,790	1,282,908

SOUTHERN CALIFORNIA GAS COMPANY
NON-CORE CUSTOMER COST ALLOCATION

Forecast Period: October 1, 1990 to September 30, 1991

FORECAST PERIOD COSTS	P28 ($000)	LARGE INDUSTRIAL ($000)	CONTRACT INDUSTRIAL ($000)	EOR/ EOR COGEN ($000)
TRANSPORTATION REVENUE REQUIREMENT				
Common distribution	5,454	23,910	869	0
Demand related transmission	2,247	8,972	346	0
Demand related storage	1,567	6,489	240	0
Customer related	719	3,079	119	0
Commodity related	0	0	0	0
50% Administrative & General	3,292	13,109	508	0
SUBTOTAL - Base (margin)	13,279	55,558	2,081	0
Net EOR Adjustment	(746)	(3,079)	(116)	65,096
Interutility transport rev.	(12)	(48)	(2)	0
Exchange revenues	(166)	(665)	(26)	0
Storage Banking Revenue	(69)	(286)	0	0
TOTAL - Adjusted Base	12,285	51,480	1,936	65,096
Pipeline demand charges	5,811	23,200	895	0
Co. use & unaccounted for (t/p)	786	3,136	120	7,828
Women Min. Bus. Ent. (WMBE)	5	20	1	0
Mutual Assist. Agree. Gas (MAA)	365	1,458	56	0
Carry Cost Storage Inv (CCSI)	38	159	6	0
Migration Losses	5	21	1	0
Gas Loss Memo Account (GLMA)	4	18	1	0
Transition costs				
Direct bills:	1,309	5,214	202	0
MPO Transition Cost Adj.	235	935	36	0
Excess Purch. Gas Costs (carried over from 1988)	161	640	25	0
TOTAL - Forecast Period Costs	21,005	86,282	3,279	72,924
AMORTIZATION OF BALANCING ACCOUNTS: INCLUDES ADJUSTMENT FOR BALANCING ACCOUNT CONSOLIDATION				
Core Fixed Cost Account (CFCA)	0	0	0	0
Core Implementation Account (CIA)	0	0	0	0
Conservation Cost Adjustment (CCA)	0	0	0	0
Enhanced Oil Recovery Account (EORA)	(281)	(1,158)	(44)	0
Negotiated Revenue Stability Account (NRSA)	(306)	(1,219)	(47)	0
Enhanced Oil Recovery Account (EORA)	(88)	(364)	(14)	0
Noncore Implementation Account (NIA)	(3,996)	(15,918)	(617)	0
Minimum Purchase Obligation (MPO)	146	582	23	0
Pipeline Demand Charges (PDC)	(224)	(893)	(34)	0
Noncore Transition Cost Account (NTCA)	0	0	0	0
Cogeneration Shortfall Account (CSA)	0	0	0	0
Carrying Cost of Storage	(44)	(182)	(7)	0
Take-or-Pay	535	2,132	83	0
Fixed Cost Acct. (NFCA) Marg. Shortfall	0	0	0	0
Conservation Cost Adjustment (CCA)	(1,829)	(7,282)	(282)	0
SUBTOTAL - Forecast Account Balances	(6,086)	(24,302)	(939)	0
TOTAL - Transportation Revenue Requirement	14,919	61,980	2,339	72,924
ALLOCATION ADJUSTMENTS				
Long-term contract shortfall	0	0	(397)	0
Long-term contract spread	102	406	0	0
CCSI Credit to wholesale	0	0	0	0
CCSI Whl. Credit Spread	75	75	3	0
TRANSPORTATION COSTS	15,096	62,461	1,946	72,924

APPENDIX G
TABLE 3
(con't)
SOUTHERN CALIFORNIA GAS COMPANY
NON-CORE CUSTOMER COST ALLOCATION

Forecast Period: October 1, 1990 to September 30, 1991

FORECAST PERIOD COSTS	CONTRACT COGEN ($000)	NON-EOR COGEN ($000)	UEG ($000)	NON-CORE TOTAL ($000)
TRANSPORTATION REVENUE REQUIREMENT				
Common distribution	1,536	6,647	0	38,415
Demand related transmission	1,513	6,796	19,551	39,424
Demand related storage	1,158	4,421	8,683	22,558
Customer related	433	1,947	1,699	7,996
Commodity related	0	0	0	0
50% Administrative & General	2,220	9,973	33,479	62,579
SUBTOTAL - Base (margin)	6,860	29,783	63,411	170,972
Net EOR Adjustment	(421)	(1,852)	(4,456)	54,425
Interutility transport rev.	(8)	(36)	(105)	(211)
Exchange revenues	(112)	(503)	(1,448)	(2,920)
Storage Banking Revenue	0	(195)	(382)	(931)
TOTAL - Adjusted Base	6,319	27,197	57,020	221,335
Pipeline demand charges	3,912	17,573	50,556	101,945
Co. use & unaccounted for (t/p)	523	2,351	7,892	22,635
Women Min. Bus. Ent. (WMBE)	3	16	52	98
Mutual Assist. Agree. Gas (MAA)	243	1,093	640	3,857
Carry Cost Storage Inv (CCSI)	28	108	212	552
Migration Losses	4	14	28	72
Gas Loss Memo Account (GLMA)	3	12	24	62
Transition costs				
Direct bills:	883	3,967	13,318	24,893
MPO Transition Cost Adj.	158	712	2,389	4,466
Excess Purch. Gas Costs (carried over from 1988)	108	487	1,636	3,057
TOTAL - Forecast Period Costs	12,185	53,529	133,767	382,971
AMORTIZATION OF BALANCING ACCOUNTS: INCLUDES ADJUSTMENT FOR BALANCING ACCOUNT CONSOLIDATION				
Core Fixed Cost Account (CFCA)	0	0	0	0
Core Implementation Account (CIA)	0	0	0	0
Conservation Cost Adjustment (CCA)	0	0	0	0
Enhanced Oil Recovery Account (EORA)	(158)	(696)	(1,675)	(4,012)
Negotiated Revenue Stability Account (NRSA)	(206)	(928)	(3,114)	(5,821)
Enhanced Oil Recovery Account (EORA)	(50)	(219)	(527)	(1,261)
Noncore Implementation Account (NIA)	(2,696)	(12,110)	(40,648)	(75,984)
Minimum Purchase Obligation (MPO)	99	443	1,486	2,778
Pipeline Demand Charges (PDC)	(151)	(676)	(1,945)	(3,923)
Noncore Transition Cost Account (NTCA)	0	0	0	0
Cogeneration Shortfall Account (CSA)	0	0	0	0
Carrying Cost of Storage	(33)	(124)	(244)	(634)
Take-or-Pay	361	1,622	5,445	10,177
Fixed Cost Acct. (NFCA) Marg. Shortfall	0	0	0	0
Conservation Cost Adjustment (CCA)	0	0	0	(9,393)
SUBTOTAL - Forecast Account Balances	(2,834)	(12,688)	(41,222)	(88,072)
TOTAL - Transportation Revenue Requirement	9,352	40,841	92,545	294,900
ALLOCATION ADJUSTMENTS				
Long-term contract shortfall	(4,563)	0	0	(4,960)
Long-term contract spread	0	309	1,038	1,855
CCSI Credit to wholesale	0	0	0	0
CCSI Whl. Credit Spread	13	51	100	260
TRANSPORTATION COSTS	4,802	41,201	93,682	292,055

APPENDIX G
TABLE 4

SOUTHERN CALIFORNIA GAS COMPANY
WHOLESALE CUSTOMER COST ALLOCATION

Forecast Period: October 1, 1990 to September 30, 1991

FORECAST PERIOD COSTS	LONG BEACH ($000)	SDG&E ($000)	TOTAL ($000)
TRANSPORTATION REVENUE REQUIREMENT			
Common distribution	0	0	0
Demand related transmission	3,256	15,230	18,486
Demand related storage	2,362	13,323	15,685
Customer related	143	3,560	3,703
Commodity related	0	0	0
50% Administrative & General	565	2,455	3,020
SUBTOTAL - Base (margin)	6,325	34,568	40,893
Net EOR Adjustment	(575)	(2,886)	(3,461)
Interutility transport rev.	(17)	(81)	(99)
Exchange revenues	(241)	(1,128)	(1,369)
Storage Banking Revenue	(104)	(586)	(690)
TOTAL - Adjusted Base	5,387	29,887	35,274
Pipeline demand charges	8,387	39,233	47,620
Co. use & unaccounted for (t/p)	1,190	4,961	6,151
Women Min. Bus. Ent. (WMBE)	8	33	41
Mutual Assist. Agree. Gas (MAA)	0	0	0
Carry Cost Storage Inv (CCSI)	58	325	382
Migration Losses	7	42	50
Gas Loss Memo Account (GLMA)	6	36	43
Transition costs			
Direct bills:	2,008	8,372	10,380
MPO Transition Cost Adj.	360	1,502	1,862
Excess Purch. Gas Costs (carried over from 1988)	0	0	0
TOTAL - Forecast Period Costs	17,411	84,391	101,803
AMORTIZATION OF BALANCING ACCOUNTS: INCLUDES ADJUSTMENT FOR BALANCING ACCOUNT CONSOLIDATION 1/			
Core Fixed Cost Account (CFCA)	0	0	0
Core Implementation Account (CIA)	0	0	0
Conservation Cost Adjustment (CCA)	0	0	0
Enhanced Oil Recovery Account (EORA)	(215)	(1,081)	(1,296)
Negotiated Revenue Stability Account (NRSA)	(469)	(1,958)	(2,427)
Enhanced Oil Recovery Account (EORA)	(68)	(340)	(407)
Noncore Implementation Account (NIA) 1/	0	0	0
Minimum Purchase Obligation (MPO)	224	934	1,158
Pipeline Demand Charges (PDC)	(323)	(1,510)	(1,832)
Noncore Transition Cost Account (NTCA) 1/	271	1,165	1,435
Cogeneration Shortfall Account (CSA)	0	0	0
Carrying Cost of Storage	(66)	(373)	(439)
Take-or-Pay	821	3,423	4,244
Fixed Cost Acct. (NFCA) Marg. Shortfall 1/	(46)	(197)	(242)
Conservation Cost Adjustment (CCA)	0	0	0
SUBTOTAL - Forecast Account Balances	129	64	193
TOTAL - Transportation Revenue Requirement	17,540	84,456	101,995
ALLOCATION ADJUSTMENTS			
Long-term contract shortfall	0	0	0
Long-term contract spread	157	655	812
CCSI Credit to Wholesale	(101)	(854)	(955)
CCSI Whl. Credit Spread	0	0	0
TRANSPORTATION COSTS	17,596	84,257	101,852

1/ NCTA and NFCA adjustments to wholesale shown for informational purposes. These adjustments were incorporated into rate design to consolidate the balancing accounts into the NIA.

APPENDIX G
TABLE 5

SOUTHERN CALIFORNIA GAS COMPANY
DISCOUNT ADJUSTMENT CALCULATION

Forecast Period: October 1, 1990 to September 30, 1991

Parameters

	P2B:	Other Industrial:
Elasticity:		
Commercial	-0.504	-0.504
Other Ind.	-0.674	-0.674
NC WACOG	0.25395	0.25395
CEILING	0.08490	0.08855
FLOOR	0.05691	0.05691

P2B COMMERCIAL

RATE	DEMAND (Mdth)	INCREMENTAL REVENUE
33.8851	1,433.3	1,216.9
32.8851	1,455.1	16.3
31.8851	1,478.0	14.8
31.0855	1,497.0	10.8
TOTAL REV.		1,258.9

P2B INDUSTRIAL

RATE	DEMAND (Mdth)	INCREMENTAL REVENUE
33.8851	14,486.2	12,299.2
32.8851	14,781.7	221.3
31.8851	15,092.5	201.8
31.0855	15,353.1	148.3
TOTAL REV.		12,870.6

OTHER COMMERCIAL

RATE	DEMAND (Mdth)	INCREMENTAL REVENUE
34.2495	13,552.5	12,000.3
33.2495	13,756.4	160.2
32.2495	13,969.8	146.3
31.0855	14,231.0	148.7
TOTAL REV.		12,455.4

OTHER INDUSTRIAL

RATE	DEMAND (Mdth)	INCREMENTAL REVENUE
34.2495	48,621.5	43,052.8
33.2495	49,602.3	770.4
32.2495	50,633.8	707.1
31.0855	51,904.0	722.8
TOTAL REV.		45,253.2

P2B Target Revenue	14,129.5
Forecast volume * Default rate	14,306.3
Discount Adjustment	98.76%
Other Industrial Target Revenue	57,708.6
Forecast volume * Default rate	58,560.6
Discount Adjustment	98.55%

TABLE 6

SOUTHERN CALIFORNIA GAS COMPANY
CORE BUNDLED RATES AND REVENUES

Forecast Period: October 1, 1990 to September 30, 1991

CORE CUSTOMER CLASS	THROUGHPUT (Mth)	PRESENT RATES ($/TH)	PRESENT REVENUES (M$)	ADOPTED RATE NON-GAS ($/TH)	ADOPTED RATE GAS ($/TH)	ADOPTED RATE TOTAL ($/TH)	ADOPTED REVENUE NON-GAS (M$)	ADOPTED REVENUE GAS (M$)	ADOPTED REVENUE TOTAL (M$)	CHANG (%)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
RESIDENTIAL										
Customer Charge		3.10	164,612			3.10	164,612		164,612	0.0%
Submetering Discount			(3,747)				(5,311)		(5,311)	41.7%
Subtotal			160,865				159,301		159,301	-1.0%
Tier 1	1,840,933	0.39480	726,800	0.15774	0.28632	0.44407	290,398	527,096	817,494	12.5%
Tier 2	1,011,237	0.75013	758,559	0.46437	0.28632	0.75069	469,590	289,538	759,128	0.1%
Residential Avg/Total	2,852,170	0.57718	1,646,224	0.32231	0.28632	0.60863	919,289	816,634	1,735,923	5.4%
CORE COMMERCIAL										
Customer Charges			26,308						26,308	
Summer										
Tier 1	424,743	0.52669	223,708	0.27391	0.28632	0.56023	116,341	121,612	237,954	6.4%
Tier 2	214,954	0.46169	99,242	0.20891	0.28632	0.49523	44,906	61,546	106,452	7.3%
Winter										
Tier 1	325,916	0.65966	214,994	0.40688	0.28632	0.69320	132,609	93,316	225,925	5.1%
Tier 2	121,753	0.50170	61,084	0.24892	0.28632	0.53524	30,307	34,860	65,167	6.7%
Commercial Avg/Total	1,087,366	0.57509	625,335	0.32231	0.28632	0.60863	350,471	311,335	661,806	5.8%
Transport Rate	17,449	0.27344	4,771	0.32231	0.00000	0.32231	5,624	0	5,624	17.9%
CORE AVERAGE/TOTAL	3,956,985	0.57527	2,276,331	0.32231	0.28506	0.60737	1,275,384	1,127,969	2,403,352	5.6%

ADOPTED LIRA RATES/DISCOUNTS	LIRA THROUGHPUT (MTH)	NON-LIRA RATE ($/TH)	LIRA RATE ($/TH)	RATE DISCOUNT ($/TH)	REVENUE DISCOUNT (M$)
Customer Charge		3.10	2.64	0.46	1,932
Submetering Adjustment					59
Tier 1	144,079	0.44407	0.37746	0.06661	9,597
Tier 2	79,144	0.75069	0.63809	0.11260	8,912
Total	223,223				20,501

LIRA Surcharge Calculation

LIRA Benefit	20,501 ($M)
LIRA A&G	731 ($M)
LIRA Balancing Acct	1,219 ($M)
Total LIRA Cost	22,451 ($M)
Nonexempt Volumes	4,616,298 (Mth)
LIRA Surcharge	0.004863 ($/th)

APPENDIX G
TABLE 7

SOUTHERN CALIFORNIA GAS COMPANY
NONCORE TRANSPORT RATES AND REVENUES

Forecast Period: October 1, 1990 to September 30, 1991

NONCORE CUSTOMER CLASS	THROUGHPUT (Mth)	PRESENT RATES ($/TH)	PRESENT REVENUES (M$)	ADOPTED RATES ($/TH)	ADOPTED REVENUES (M$)	(M$)	ADOPTED CHANGE (%)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
PRIORITY P28							
Customer Charge			467		530	63	13.6%
01	177,134	0.01114	1,973	0.00000	0	-1973	-100.0%
02							
Summer	147,612	0.01487	2,195	0.01489	2,198	3	0.1%
Winter	73,806	0.03181	2,348	0.02946	2,174	-173	-7.4%
Volumetric Charge	177,134	0.05587	9,896	0.05723	10,137	240	2.4%
TOTAL/AVG P28	177,134	0.09529	16,879	0.08490	15,039	-1840	-10.9%
INDUSTRIAL							
Customer Charge			2,211		2,274	63	2.8%
01	705,402	0.01061	7,484	0.00000	0	-7484	-100.0%
02							
Summer	587,835	0.01559	9,164	0.01640	9,640	475	5.2%
Winter	293,917	0.03439	10,108	0.03155	9,273	-835	-8.3%
Volumetric Charge	705,402	0.05593	39,453	0.05851	41,275	1822	4.6%
Ind. Net LT Contract	705,402	0.09700	68,421	0.08855	62,461	-5959	-8.7%
Ind. LT Contract	27,320		2,280		1,946	-334	-14.7%
TOTAL INDUSTRIAL	732,722	0.09649	70,701	0.08790	64,407	-6294	-8.9%
P28 & INDUSTRIAL	909,856	0.09626	87,580	0.08732	79,446	-8134	-9.3%
UTILITY ELECTRIC GEN							
Demand Charge	1,801,577	0.03241	58,389	0.01843	33,200	-25189	-43.1%
Volumetric Charge							
Tier 1	374,816	0.13743	51,511	0.07398	27,730	-23781	-46.2%
Tier 2	1,426,761	0.01663	23,727	0.02915	41,592	17865	75.3%
UEG Minus Igniter	1,801,577	0.07417	133,627	0.05691	102,522	-31105	-23.3%
Igniter	23,350	0.29625	6,917	0.32231	7,526	609	8.8%
TOTAL UEG	1,824,927	0.07701	140,544	0.06030	110,048	-30496	-21.7%
COGENERATION							
Cogen Net LT Contracts	536,645	0.07475	40,114	0.06030	32,361	-7753	-19.3%
Cogen LT Contracts	119,450		4,678		4,802	124	2.6%
TOTAL/AVG COGEN	656,095	0.06827	44,792	0.05664	37,163	-7629	-17.0%
NONCORE SUBTOTAL							
Net of LT Contracts	3,220,758	0.08043	259,041	0.06828	219,910	-39131	-15.1%
Include LT Contracts	3,367,528	0.07899	265,999	0.06731	226,658	-39342	-14.8%
WHOLESALE							
Long Beach							
Demand Charge	272,622	0.03837	10,461	0.02606	7,106	-3355	-32.1%
Volumetric Charge	272,622	0.03897	10,624	0.03848	10,490	-134	-1.3%
Total Long Beach	272,622	0.07734	21,085	0.06454	17,596	-3489	-16.5%
SDG&E							
Demand Charge	1,136,917	0.04519	51,377	0.06123	69,616	18238	35.5%
Tier 1 Rate				0.00785	6,229		
Tier 2 Rate				0.02697	8,061		
Tier 3 Rate				0.00785	351		
Total Vol. Charge	1,136,917	0.03897	44,306	0.01288	14,641	-29665	-67.0%
Total SDG&E	1,136,917	0.08416	95,683	0.07411	84,257	-11426	-11.9%
TOTAL WHOLESALE	1,409,540	0.08284	116,768	0.07226	101,852	-14915	-12.8%
TOTAL NONCORE							
Net of LT Contracts	4,630,297	0.08116	375,809	0.06949	321,763	-54046	-14.4%
Include LT Contracts	4,777,067	0.08013	382,767	0.06877	328,510	-54257	-14.2%
Brokerage Fee	1,588,666.7	0.00196	3,113.8	0.00249	3,960	846	27.2%

Table 8

Southern California Gas Company

1989 Tracking Accounts Surcharge
Effective until January 14, 1991

Class of Service	Surcharge Amount - ¢/th(2)
Core, all	.327
Noncore	
P-2B D-1 Demand Charge	(.408)
Volumetric	.803
Other Industrial - D-1 Demand Charge	(.415)
Volumetric	.803
Cogeneration(3)	.486
UEG(3) Igniter Service	.327
Demand Charge	(.317)
Tier I Volumetric	4.339
Long Beach - Demand Charge	(.417) (4)
Volumetric	.803
SDG&E - Demand Charge	(.454) (4)
Volumetric	.803

(1) There are four tracking accounts:
   (a) Interstate Pipeline Demand Charges
   (b) MPO's
   (c) CCSI
   (d) Take-or-pay.

The Surcharge is to be effective from the date of 1990 ACAP implementation through January 14, 1991 in order to complete the 12 month recovery cycle.

(2) Additive to SoCalGas proposed rates.

(3) Includes parity adjustment.

(4) Average UEG Volumetric Surcharge Rate based on total of Tier I and Tier II volumes.

(END OF APPENDIX G)

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1990 to September 30, 1991

TABLE 1

ADOPTED GAS DEMAND

THROUGHPUT TYPE	FORECASTED DEMAND (MMth)
Residential	334.26
Commercial Core	117.14
Comm/Industrial Non-Core	55.40
Retail UEG	427.11
Cogeneration	192.20
Company use	3.00
Unaccounted for	7.81
TOTAL GAS DEMAND	1136.92

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1990 to September 30, 1991

TABLE 2

ADOPTED SUPPLY FORECASTS by CUSTOMER CLASS

CUSTOMER CLASS	PRIORITY	SUPPLY FORECASTS (MMth)
Residential	P-1	334.26
Commercial	P-1	103.71
Commercial	P-2A	10.89
Commercial Igniter Fuel S-T Trn	P-2A	2.54
Industrial	P-2B	12.74
Industrial	P-3B	42.66
Cogeneration	P-3A	192.20
Steam	P-4	1.11
UEG	P-3	78.81
UEG	P-3AA	336.27
UEG	P-5	10.92
Company use S-T Trn	P-1	3.00
Unaccounted for S-T Trn	P-1	7.81
TOTAL GAS DELIVERIES		1136.92

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1990 to September 30, 1991

TABLE 3

ADOPTED SUPPLY FORECAST by PORTFOLIO CLASS

	0.0 (MMth)
CORE & CORE-ELECT PORTFOLIO	
Residential	332.25
Commercial	102.69
Comm. GN-2A & Igniter	10.28
Industrial	2.65
Cogeneration	0.48
UEG	0.00
TOTAL	448.35
NON-CORE PORTFOLIO	
Comm. GN-2A & Igniter	2.54
Industrial	61.51
Cogeneration	86.88
UEG	427.11
TOTAL	578.03
SHORT-TERM TRANSPORT	
Residential	2.01
Commercial	0.01
Comm. GN-2A & Igniter	1.62
Industrial	4.75
Cogeneration	91.34
UEG	0.00
TOTAL	99.73
Company use	3.00
Unaccounted for	7.80
TOTAL ALL PORTFOLIOS	1136.91

(END OF APPENDIX H)

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1990 to September 30, 1991

TABLE 1

ADOPTED GAS COSTS

	VOLUMES (MMth)	PRICE ($/th)	COSTS ($000)
Core & Core-Elect Supplies			
Core/Core-elect	448		112,086.5
Core & Core-elect WACOG		0.2500	
Core Purchased Gas Account (CPGA)			(3,395.0)
Subtotal			108,691.5
Non-Core Supplies			
Non-core purchases	578	0.2548	147,282.6
TOTAL GAS COSTS			255,974.1

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1990 to September 30, 1991

TABLE 2

ADOPTED PORTFOLIO PRICES

	VOLUMES (MMth)		COSTS ($000)
Core & Core-elect Portfolio			
Core & Core-elect purchases	448		112,086.5
Add: Core Purchased Gas Account (CPGA)			3,639.0
Subtotal			115,725.5
Add: FF&U 2.490%			2,881.6
CORE AND CORE-ELECT SALES	448.3		118,607.1
CORE AND CORE-ELECT PORTFOLIO PRICE		$2.6454 /dth	
Non-Core Portfolio			
Non-core porfolio demand	578		147,282.6
Add: FF&U 2.490%			3,667.3
NON-CORE PORTFOLIO SALES	578		150,949.9
NON-CORE PORTFOLIO PRICE ($/dth)		$2.6114 /dth	

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1990 to September 30, 1991

TABLE 3

ADOPTED REVENUE REQUIREMENTS

PROCUREMENT REVENUE REQUIREMENT	($000)	
Total Core Procurement Revenue	118,607.1	
Total Non-core Procurement Revenue	150,949.9	
TOTAL PROCUREMENT REVENUE REQUIREMENT		269,557.0
TRANSMISSION REVENUE REQUIREMENT		
SDG&E's authorized gas margin:		
Common distribution	45,831.0	
Demand related transmission	9,413.0	
Demand related storage	605.0	
Customer related	70,353.0	
Commodity related	1,642.0	
50% Administrative & General	10,479.0	138,323.0
Core Co. use and unaccounted for gas	1,137.4	
Non-Core Co. use and unaccounted gas	1,447.6	
Carrying Cost of Storage	1,631.0	
Carrying Cost of Storage-Prior Period	1,600.0	5,816.1
F&U on SDG&E Other Costs		97.2
SoCal's authorized gas margin allocated to SDG&E:		
Common distribution	0.0	
Demand related transmission	15,230.0	
Demand related storage	13,323.0	
Pipeline Demand Charges	39,233.0	
Customer Related	3,560.0	
EOR Adjustment	(2,886.0)	
50% Administrative & General	2,455.0	
F&U	1,041.8	71,956.8
Other SoCal costs allocated to SDG&E:		
Carrying cost of storage	325.0	
Prior Period Cost of Storage	(854.0)	
Company use and Unaccounted for	4,961.0	
Women Min. Bus. Ent. (WMBE)	33.0	
Net long-term shortfall	655.0	
Excess Purch. Gas Costs (from 1988)	0.0	
Storage Banking Revenue	(586.0)	
Transition costs	8,372.0	
Minimum Purchase Obligations	1,502.0	
Interutility transportation revenues	(81.0)	
Migration Losses	42.0	
Gas Loss Memo Account (GLMA)	36.0	
Exchange revenues	(1,128.0)	
F&U on other SoCal Costs	177.5	13,454.5

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1990 to September 30, 1991

TABLE 3 Contd

ADOPTED REVENUE REQUIREMENTS

	($000)	
SDG&E'S BALANCING /TRACKING ACCOUNTS		
Other Core accounts:		
Core Fixed Cost Account (CFCA)	(16,223.0)	
Core Implementation Account (CIA)	(4,883.0)	
F&U	(525.5)	(21,631.5)
Non-Core accounts:		
Negotiated Revenue Stability Account	0.0	
Enhanced Oil Recovery Account (EORA)	0.0	
Noncore Implementation Account (NIA)	(6,938.0)	
Minimum Purchase Obligation (MPO)	0.0	
Pipeline Demand Charges (PDC)	0.0	
Noncore Transition Cost Account (NTCA	(516.0)	
Cogeneration Shortfall Account (CSA)	0.0	
Carrying Cost of Storage	0.0	
Take-or-Pay	0.0	
F&U	(68.1)	(7,522.1)
SOCAL'S BALANCING/TRACKING ACCOUNTS ALLOCATED TO SDG&E		
Non-Core accounts:		
Negotiated Revenue Stability Account	(1,958.0)	
Enhanced Oil Recovery Account (EORA)	(1,421.0)	
Noncore Implementation Account (NIA)	0.0	
Minimum Purchase Obligation (MPO)	934.0	
Pipeline Demand Charges (PDC)	(1,510.0)	
Noncore Transition Cost Account (NTCA	1,165.3	
Cogeneration Shortfall Account (CSA)	0.0	
Carrying Cost of Storage	(373.0)	
Take-or-Pay	3,423.0	
Fixed Cost Acct. (NFCA) Marg. Shortfa	(197.0)	
F&U	0.8	64.1
TRANSMISSION REVENUE REQUIREMENT		200,558.1
MISCELLANEOUS REVENUE		(3,152.0)
TOTAL TRANSMISSION REVENUE REQUIREMENT		197,406.1
AVERAGE TRANSMISSION RATE (c/th)		17.8
CORE PROCUREMENT REVENUE		117,778.8
TOTAL REVENUE REQUIREMENT		315,184.8
NET LIRA COSTS		801.5
NET REVENUE REQUIREMENT		315,986.3

(END OF APPENDIX I)

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1990 to September 30, 1991

TABLE 1

ADOPTED CORE CUSTOMER COST ALLOCATION

	RESIDENTIAL	GN-1	GN-2A & UEG IGNITER	TOTAL CORE
		($000)		
TRANSMISSION FIXED COSTS				
SDG&E's authorized gas margin				
Common distribution	29,207.5	6,741.4	929.4	36,878.3
Demand related transmission	3,076.6	873.3	121.5	4,071.4
Demand related storage	256.7	61.8	8.2	326.8
Customer related	65,900.7	3,458.9	39.4	69,399.0
Commodity related	487.4	149.7	21.1	658.2
50% Administrative & General	3,110.4	955.6	134.4	4,200.5
Core Co. use and unaccounted for gas	337.6	103.7	14.6	455.9
Non-Core Co. use and unaccounted gas	429.7	132.0	18.6	580.3
Carrying Cost of Storage	692.1	166.6	22.2	880.9
Carrying Cost of Storage-Prior Period	678.9	163.4	21.8	864.2
F&U on SDG&E Other Costs	53.2	14.1	1.9	69.3
SoCal's gas margin allocated to SDG&E (incl. EOR adjust):				
Common distribution	0.0	0.0	0.0	0.0
Demand related transmission	4,783.2	1,357.7	188.9	6,329.8
Demand related storage	5,432.4	1,307.4	174.5	6,914.3
Pipeline Demand Charges	12,321.7	3,497.4	486.6	16,305.8
Customer Related	1,118.1	317.4	44.2	1,479.6
EOR Adjustment				0.0
50% Administrative & General	700.2	215.1	30.3	945.6
F&U	606.5	166.7	23.0	796.2
Other SoCal costs allocated to SDG&E:				
Carrying cost of storage	137.9	33.2	4.4	175.5
Prior Period Cost of Storage	(362.4)	(87.2)	(11.6)	(461.2)
Company use and Unaccounted for	1,621.5	460.2	64.0	2,145.8
Women Min. Bus. Ent. (WMBE)	10.8	3.1	0.4	14.3
Net long-term shortfall	194.4	59.7	8.4	262.6
Excess Purch. Gas Costs (from 1988)	0.0	0.0	0.0	0.0
Storage Banking Revenue	(248.7)	(59.8)	(8.0)	(316.5)
Transition costs	2,485.0	763.5	107.4	3,355.9
Minimum Purchase Obligations	445.8	137.0	19.3	602.1
Interutility transportation revenues	(26.5)	(7.5)	(1.0)	(35.0)
Migration Losses	17.8	4.3	0.6	22.7
Gas Loss Memo Account (GLMA)	15.3	3.7	0.5	19.4
Exchange revenues	(368.7)	(104.6)	(14.6)	(487.9)
F&U on other SoCal Costs	97.7	30.0	0.0	127.7

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1990 to September 30, 1991

TABLE 1 Contd

ADOPTED CORE CUSTOMER COST ALLOCATION

	RESIDENTIAL	GN-1	GN-2A & UEG IGNITER	TOTAL CORE
SDG&E'S BALANCING /TRACKING ACCOUNTS		($000)		
Other Core accounts:				
Core Fixed Cost Account (CFCA)	(12,013.1)	(3,690.7)	(519.2)	(16,223.0)
Core Implementation Account (CIA)	(3,615.9)	(1,110.9)	(156.3)	(4,883.0)
F&U	(389.2)	(119.6)	(16.8)	(525.5)
Non-Core accounts:				
Negotiated Revenue Stability Accoun	0.0	0.0	0.0	0.0
Enhanced Oil Recovery Account (EORA	0.0	0.0	0.0	0.0
Noncore Implementation Account (NIA	0.0	0.0	0.0	0.0
Minimum Purchase Obligation (MPO)	0.0	0.0	0.0	0.0
Pipeline Demand Charges (PDC)	0.0	0.0	0.0	0.0
Noncore Transition Cost Account (NT	0.0	0.0	0.0	0.0
Cogeneration Shortfall Account (CSA	0.0	0.0	0.0	0.0
Carrying Cost of Storage	0.0	0.0	0.0	0.0
Take-or-Pay	0.0	0.0	0.0	0.0
F&U	0.0	0.0	0.0	0.0
SOCAL'S BALANCING/TRACKING ACCOUNTS ALLOCATED TO SDG&E				
Non-Core accounts (EOR account included)				
Negotiated Revenue Stability Accoun	(24.8)	(7.6)	(1.1)	(33.5)
Enhanced Oil Recovery Account (EORA)				
Noncore Implementation Account (NIA	0.0	0.0	0.0	0.0
Minimum Purchase Obligation (MPO)	11.8	3.6	0.5	16.0
Pipeline Demand Charges (PDC)	(21.0)	(6.0)	(0.8)	(27.9)
Noncore Transition Cost Account (NT	14.8	4.5	0.6	19.9
Cogeneration Shortfall Account (CSA	0.0	0.0	0.0	0.0
Carrying Cost of Storage	(6.7)	(1.6)	(0.2)	(8.6)
Take-or-Pay	43.3	13.3	1.9	58.5
Fixed Cost Acct. (NFCA) Marg. Short	(2.5)	(0.8)	(0.1)	(3.4)
F&U	0.4	0.1	0.0	0.5
TRANSMISSION REVENUE REQ.	117,210.2	16,002.1	1,758.9	134,971.2
MISCELLANEOUS REVENUE	(1,842.1)	(251.5)	(27.6)	(2,121.2)
TOTAL TRANSMISSION REVENUE REQ	115,368.1	15,750.6	1,731.3	132,850.0
AVERAGE TRANSMISSION RATE (c/th)	35.1	15.6	12.2	29.9
CORE PROCUREMENT REVENUE				117,778.8
TOTAL REVENUE REQUIREMENT				250,628.7
NET LIRA COSTS				801.5
NET REVENUE REQUIREMENT				251,430.2

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1990 to September 30, 1991

TABLE 2

ADOPTED NONCORE CUSTOMER COST ALLOCATION

	INDUSTRIAL	COGEN	UEG GAS DEPT GN-3 TO GN-5	TOTAL	SYSTEM TOTAL
		($000)			
TRANSMISSION FIXED COSTS					
SDG&E's authorized gas margin					
Common distribution	3,654.7	5,298.1	0.0	8,952.7	45,831.0
Demand related transmission	564.9	1,414.9	3,361.8	5,341.6	9,413.0
Demand related storage	33.4	70.7	174.2	278.2	605.0
Customer related	163.9	497.7	292.5	954.0	70,353.0
Commodity related	100.5	260.6	622.8	983.8	1,642.0
50% Administrative & General	641.3	1,662.8	3,974.5	6,278.5	10,479.0
Core Co. use and unaccounted for gas	69.6	180.5	431.4	681.5	1,137.4
Non-Core Co. use and unaccounted gas	88.6	229.7	549.0	867.3	1,447.6
Carrying Cost of Storage	89.9	190.6	469.5	750.1	1,631.0
Carrying Cost of Storage-Prior Period	88.2	187.0	460.6	735.8	1,600.0
F&U on SDG&E Other Costs	8.4	19.6	0.0	28.0	97.2
SoCal's authorized gas margin allocated to SDG&E:					
Common distribution	0.0	0.0	0.0	0.0	0.0
Demand related transmission	878.2	2,199.8	5,226.6	8,304.6	14,634.4
Demand related storage	706.0	1,496.2	3,685.4	5,887.7	12,802.0
Pipeline Demand Charges	2,262.3	5,666.8	13,463.9	21,393.0	37,698.8
SDG&E-SOCAL transmission interconnect	205.3	514.2	1,221.7	1,941.2	3,420.8
EOR Adjustment					
50% Administrative & General	144.4	374.3	894.7	1,413.4	2,359.0
F&U	71.3	174.3	0.0	245.6	1,041.8
Other SoCal costs allocated to SDG&E:					
Carrying cost of storage	17.9	38.0	93.6	149.5	325.0
Prior Period Cost of Storage	(47.1)	(99.8)	(245.8)	(392.8)	(854.0)
Company use and Unaccounted for	297.7	745.7	1,771.8	2,815.2	4,961.0
Women Min. Bus. Ent. (WMBE)	2.0	5.0	11.8	18.7	33.0
Net long-term shortfall	40.1	103.9	248.4	392.4	655.0
Excess Purch. Gas Costs (from 1988)	0.0	0.0	0.0	0.0	0.0
Storage Banking Revenue	(32.3)	(68.5)	(168.7)	(269.5)	(586.0)
Transition costs	512.3	1,328.5	3,175.3	5,016.1	8,372.0
Minimum Purchase Obligations	91.9	238.3	569.7	899.9	1,502.0
Interutility transportation revenues	(4.9)	(12.2)	(28.9)	(46.0)	(81.0)
Migration Losses	2.3	4.9	12.1	19.3	42.0
Gas Loss Memo Account (GLMA)	2.0	4.2	10.4	16.6	36.0
Exchange revenues	(67.7)	(169.6)	(402.9)	(640.1)	(1,128.0)
F&U on other SoCal Costs	13.8	36.0	0.0	49.9	177.5

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1990 to September 30, 1991

TABLE 2 Contd

ADOPTED NONCORE CUSTOMER COST ALLOCATION

	INDUSTRIAL	COGEN	UEG GAS DEPT GN-3 TO GN-5	TOTAL	SYSTEM TOTAL
SDG&E'S BALANCING /TRACKING ACCOUNTS			($000)		
Other Core accounts:					
Core Fixed Cost Account (CFCA)	0.0	0.0	0.0	0.0	(16,223.0)
Core Implementation Account (CIA)	0.0	0.0	0.0	0.0	(4,883.0)
F&U	0.0	0.0	0.0	0.0	(525.5)
Non-Core accounts:					
Negotiated Revenue Stability Account	0.0	0.0	0.0	0.0	0.0
Enhanced Oil Recovery Account (EORA)	0.0	0.0	0.0	0.0	0.0
Noncore Implementation Account (NIA)	(708.6)	(1,837.5)	(4,391.9)	(6,938.0)	(6,938.0)
Minimum Purchase Obligation (MPO)	0.0	0.0	0.0	0.0	0.0
Pipeline Demand Charges (PDC)	0.0	0.0	0.0	0.0	0.0
Noncore Transition Cost Account (NTCA	(52.7)	(136.7)	(326.6)	(516.0)	(516.0)
Cogeneration Shortfall Account (CSA)	0.0	0.0	0.0	0.0	0.0
Carrying Cost of Storage	0.0	0.0	0.0	0.0	0.0
Take-or-Pay	0.0	0.0	0.0	0.0	0.0
F&U	(19.0)	(49.2)	0.0	(68.1)	(68.1)
SOCAL'S BALANCING/TRACKING ACCOUNTS ALLOCATED TO SDG&E					
Non-Core accounts:					
Negotiated Revenue Stability Account	(5.1)	(13.3)	(31.7)	(50.0)	(83.5)
Enhanced Oil Recovery Account (EORA)					
Noncore Implementation Account (NIA)	0.0	0.0	0.0	0.0	0.0
Minimum Purchase Obligation (MPO)	2.4	6.3	15.1	23.9	39.8
Pipeline Demand Charges (PDC)	(3.9)	(9.7)	(23.0)	(36.5)	(64.4)
Noncore Transition Cost Account (NTCA	3.0	7.9	18.8	29.8	49.7
Cogeneration Shortfall Account (CSA)	0.0	0.0	0.0	0.0	0.0
Carrying Cost of Storage	(0.9)	(1.9)	(4.6)	(7.3)	(15.9)
Take-or-Pay	8.9	23.2	55.4	87.5	146.0
Fixed Cost Acct. (NFCA) Marg. Shortfa	(0.5)	(1.3)	(3.2)	(5.0)	(8.4)
F&U	0.1	0.2	0.0	0.3	0.8
TRANSMISSION REVENUE REQUIREMENT	9822.8	20580.5	35183.6	65586.9	200,558.1
MISCELLANEOUS REVENUE	(154.4)	(323.4)	(552.9)	(1,030.8)	(3,152.0)
TOTAL TRANSMISSION REVENUE REQ	9,668.5	20,257.0	34,630.6	64,556.1	197,406.1
AVERAGE TRANSMISSION RATE (c/th)	14.3	11.5	8.2	9.7	17.8
CORE PROCUREMENT REVENUE					117,778.8
TOTAL REVENUE REQUIREMENT					315,184.8
NET LIRA COSTS					801.5
NET REVENUE REQUIREMENT					$315,986.3

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1990 to September 30, 1991

Table 3

NONCORE TRANSPORT RATES AND REVENUES

Noncore Customer Class	Throughput (Mth)	Present Nongas Rates ($/TH)	Present Revenues (M$)	Proposed Revenues (M$)	Proposed Nongas Rates ($/TH)	Change (%)	Prop. Rates Incl. LIRA ($/TH)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
INDUSTRIAL							
Customer Charge			158	132.9		-15.88%	
Demand Charges							
01	68,912	0.04407	3,037	2,809.3	0.04077	-7.50%	0.04876
02				2,760.4			
Summer	61,684	0.02537	1,565	1,310.0	0.02124	-16.29%	0.02923
Winter	35,213	0.03267	1,150	1,586.3	0.04505	37.89%	0.05304
Volumetric Charge	68,912	0.06539	4,506	3,966.7	0.05756	-11.97%	0.06555
INDUSTRIAL TOTAL	68,912	0.15116	10,416	9669.3	0.14031	-7.17%	0.14831
UTILITY ELECTRIC GENERATION							
Demand Charge	427,110	0.04145	17,704	22985.4	0.05382	29.83%	0.05382
Volumetric Charge							
Tier 1	79,015	0.06812	5,383	5382.5	0.06812	0.00%	0.06812
Tier 2	348,095	0.03404	11,849	10187.2	0.02927	-14.03%	0.02927
UEG Minus Igniter	427,110	0.08180	34,936	38,555	0.09027	10.36%	0.09027
Igniter	2,540	0.35448	900	747.5	0.29429	-16.98%	0.29429
UEG TOTAL	429,650	0.12461	53,540	39302.6	0.09148	-26.59%	0.09148
COGENERATION	178,691	0.10160	18,155	16345.9	0.09148	-9.96%	0.09148
NONCORE GRAND TOTAL	677,253	0.12124	82,111	65317.8	0.09645	-20.45%	0.09726

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1990 to September 30, 1991

Table 4

CORE BUNDLED RATES AND REVENUES

Core Customer Class	Throughput (MTH)	Present Rates ($/TH)	Present Revenues (M$)	Adopted Non-Gas Rate ($/TH)	Adopted Gas Rate ($/TH)	Adopted Total Rate ($/TH)	Adopted Non-Gas Rev (M$)	Adopted Gas Rev (M$)	Adopted Total Rev (M$)	Revenue Change (%)	Rate Incl. LIRA
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
RESIDENTIAL GR											
Tier 1	173,997	0.49813	86,673	0.22783	0.26454	0.49237	39,642	46,030	85,672	-1.2%	0.50037
Tier 2	89,165	0.86796	77,391	0.46151	0.26454	0.72605	41,150	23,588	64,738	-16.3%	0.73404
Employee Discount			(327)				(305)		(305)	-6.7%	0.00799
Total GR	263,162	0.62219	163,738	0.29429	0.26454	0.57039	80,487	69,618	150,105	-8.3%	0.57838
RESIDENTIAL GS											
Tier 1	1,601	0.49813	798	0.22783	0.26454	0.49237	365	424	788	-1.2%	0.50037
Tier 2	356	0.86796	309	0.46151	0.26454	0.72605	164	94	259	-16.3%	0.73404
Unit Discount			(133)				(133)		(133)	0.0%	0.00799
Total GS	1,958	0.49768	974	0.29429	0.26454	0.46715	397	518	915	-6.1%	0.47514
RESIDENTIAL GT											
Tier 1	9,092	0.49813	4,529	0.22783	0.26454	0.49237	2,072	2,405	4,477	-1.2%	0.50037
Tier 2	3,334	0.86796	2,893	0.46151	0.26454	0.72605	1,538	882	2,420	-16.3%	0.73404
Unit Discount			(2,000)				(2,000)		(2,000)	0.0%	
Total GT	12,426	0.43643	5,423	0.29429	0.26454	0.39414	1,610	3,287	4,898	-9.7%	0.40213
RESIDENTIAL GM											
Tier 1	42,634	0.49813	21,237	0.22783	0.26454	0.49237	9,713	11,279	20,992	-1.2%	0.50037
Tier 2	12,066	0.86796	10,473	0.46151	0.26454	0.72605	5,569	3,192	8,761	-16.3%	0.73404
Total GM	54,700	0.57971	31,710	0.29429	0.26454	0.54392	15,282	14,471	29,753	-6.2%	0.55191
RESIDENTIAL GR,GS,GT,GM											
Tier 1	227,325	0.49813	113,238	0.22783	0.26454	0.49237	51,792	60,137	111,929	-1.2%	0.50037
Tier 2	104,921	0.86796	91,067	0.46151	0.26454	0.72605	48,422	27,756	76,178	-16.3%	0.73404
Discounts			(2,459)				(2,437)		(2,437)	-0.9%	0.00799
Total GR,GS,GT,GM	332,246	0.60752	201,845	0.29429	0.26454	0.55883	97,776	87,894	185,670	-8.0%	0.56682

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1990 to September 30, 1991

Table 4 Contd

CORE BUNDLED RATES AND REVENUES

Core Customer Class	Throughput (MTH)	Present Rates ($/TH)	Present Revenues (M$)	Adopted Non-Gas Rate ($/TH)	Adopted Gas Rate ($/TH)	Adopted Total Rate ($/TH)	Adopted Non-Gas Rev (M$)	Adopted Gas Rev (M$)	Adopted Total Rev (M$)	Revenue Change (%)	Rate Incl. LIRA ($/TH)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
Transportation Only	2,014	0.36003	725	0.29429		0.29429	593		593	-18.3%	
RESIDENTIAL TOTAL	334,260	0.60603	202,570	0.29429	0.26454	0.55883	98,369	87,894	186,262	-8.1%	0.56682
CORE COMMERCIAL											
GN-1 Service Char	329,268	5.00	1,646	5.00		5.00	1,646		1,646	0.0%	
GN-2 Service Char	276	60.00	17	60.00		60.00	17		17	0.0%	
Winter											
Tier 1	31,329	0.70294	22,022	0.41287	0.26454	0.67742	12,935	8,288	21,223	-3.6%	0.68541
Tier 2	17,178	0.41616	7,149	0.13651	0.26454	0.40105	2,345	4,544	6,889	-3.6%	0.40904
Summer											
Tier 1	45,131	0.59476	26,842	0.30748	0.26454	0.57202	13,877	11,939	25,816	-3.8%	0.58001
Tier 2	19,331	0.40555	7,840	0.12550	0.26454	0.39004	2,426	5,114	7,540	-3.8%	0.39804
Commercial Subtotal	112,969	0.57995	65,516	0.29429	0.26454	0.55883	33,245	29,885	63,131	-3.6%	0.56682
Transportation Only	1,630	0.36003	587	0.29429		0.29429	480		480	-18.3%	
COMMERCIAL TOTAL	114,599	0.57682	66,103	0.29429	0.26454	0.55883	33,725.1	29,885.2	63,610	-3.8%	0.56682
CORE GRAND TOTAL	448,859	0.59857	268,673	0.29429	0.26454	0.55883	132,094	117,779	249,873	-7.0%	0.56682

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1990 to September 30, 1991

Table 5

LIRA RATES AND SURCHARGE

Proposed LIRA Rates and Discounts	LIRA Throughpu (MTH)	Non-LIRA Rate ($/TH)	LIRA Rate ($/TH)	Rate Discount ($/TH)	Revenue Discount (M$)
Tier 1	19641	0.49237	0.41852	0.07386	2120
Tier 2	9065	0.72605	0.61714	0.10891	987
Total	28706				3107

LIRA SURCHARGE		
LIRA Qualifying Volumes (MMth)		28.7
LIRA Rate Discount		15.00%
LIRA Balancing Account(M$)		664.0
LIRA A&G		118.0
LIRA A&G incl. f&u	(M$)	121
LIRA Bal. Acct incl. f&u(M$)		681
Total LIRA Cost	(M$)	3,909
LIRA Benefit	(M$)	3,107
NET LIRA COSTS	(M$)	801.5
Nonexempt Volumes	(MTH)	489,065
LIRA Surcharge	($/TH)	0.007992

SAN DIEGO GAS & ELECTRIC COMPANY
Forecast Period: October 1, 1990 to September 30, 1991

Table 6

ROADRUNNER CLUB (SCHEDULE GL-1) RATES

	Present Rates	Adopted Rates	Change (%)
Facilities Charge ($/Month)	13.10	13.82	5.5%
Commodities Charge ($/Therm)	0.62565	0.72218	15.4%

(END OF APPENDIX J)

A.90-03-018, A.90-03-049
D. 90-11-023

COMMISSIONER FREDERICK R. DUDA, Concurring:

I believe today's decision in SoCalGas' and SDG&E's second ACAP, on balance, is a good decision. However, there is one issue in this decision which concerns me. This has to do with the forecast of spot gas border prices. My concern is not with the direct implications that these prices have on the case. Given the full balancing account treatment for the core and the market driven response to prices for the noncore, the gas price forecast in this decision will not directly impact ratepayers in the short run. Rather, my concern arises from the indirect impact that this information signals to SoCalGas, the other local distribution companies regulated by the Commission, and the market as a whole and the implications for core ratepayers in terms of gas costs in the long run.

The discussion in this decision which adopts an average border price of $2.50/MMBtu for the forecast period relies to a great extent on the turmoil in the world oil markets and the notion that gas prices follow oil prices. The recent restructuring in the natural gas market, and one of the justifications for it, is that it will enhance gas-on-gas competition and thereby effectively decouple the prices of oil and gas.

The decision correctly points out that for oil and gas prices in effect during the recent past, i.e. before the crisis in the Middle East, virtually all of SoCal's fuel-switching customers have been burning gas. I suspect a similar statement could be made for the country as a whole.

In addition, both SoCalGas and DRA assume slower growth in the economy during the forecast period. The recent events in the Middle East and the impact this has had on the U.S. economy both confirms and reinforces the slower growth scenarios for the coming year.

Taking these two factors into consideration, it is difficult to justify that higher prices will be the result of demand driven considerations. If it is not demand considerations that will be driving prices higher, then the only other argument is that it must be supply driven. Given that higher oil prices will have the effect, at least in the long run, of causing higher supplies of gas because of the associated nature of oil and gas, there must be some identifiable factor responsible for reducing the supply of gas in the short run. The competitive nature of the gas production market makes it difficult to justify that some type of collusive behavior is occurring on the part of producers to reduce supply and drive up prices.

This skepticism is justified by recent historical data. While oil prices have risen by nearly two and one half times for the period July 1, 1990 to October 1, 1990, gas prices have shown none of this price rise. It is only as we approach the winter heating season that we see the normal increase in prices because of weather related seasonal market (supply and demand) considerations.

In conclusion, I believe adopting gas prices based on the notion that gas prices follow oil prices, as this decision does, will likely become a self-fulfilling prophesy when it comes to SoCalGas' and other LDC's future long-term contract negotiations with their suppliers. If this is the case, the impact of the gas price forecast in this decision will be to unnecessarily ratchet up the price that core ratepayers in California pay for natural gas. This is unwarranted under the circumstances.

Frederick R. Duda, Commissioner

November 9, 1990
San Francisco, California