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Decision 00-04-060 April 20, 2000

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of SOUTHERN CALIFORNIA GAS COMPANY for Authority to Revise its Rates Effective August 1, 1999, in its Biennial Cost Allocation Proceeding. (U904 G)	Application 98-10-012 (Filed October 1, 1998)
In the Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY for Authority to Revise its Gas Rates Effective August 1, 1999, in its Biennial Cost Allocation Proceeding. (U902 G)	Application 98-10-031 (Filed October 15, 1998)

(Appearances are listed in Appendix F.)

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ABBREVIATIONS AND ACRONYMS

NAMES	ABBREVIATIONS AND ACRONYMS
Administrative and General	A&G
Administrative Law Judge	ALJ
Automatic Meter Reading	AMR
Biennial Cost Allocation Proceeding	BCAP
California Cogeneration Council and Watson Cogeneration Company	CCC/Watson
California Energy Commission	CEC
California Gas Report	CGR
California Industrial Group and California Manufacturers Association	CIG/CMA
certificate of public convenience and necessity	CPC&N
City of Long Beach	LB
City of Vernon	Vernon
Cogenerator Gas Allowance	CGA
Commercial and Industrial	C&I
Competition Transition Costs	CTCs
Core Fixed Cost Account	CFCA
Demand Side Management	DSM
Department of General Services	GS
Direct Assistance Program	DAP
Distribuidora de Gas Natural de Mexicali	DGN
Division of Ratepayer Advocates	DRA
El Paso Natural Gas Company	El Paso
Electric Generation	EG
Electric Generator Alliance	EGA
Electric Vehicles	EV
Enhanced Oil Recovery	EOR
Equal Percent of Marginal Cost	EPMC
Federal Energy Regulatory Commission	FERC
Gas Cost Incentive Mechanism	GCIM
Gas Industry Restructuring	GIR
Heating Degree Days	HDD

NAMES	ABBREVIATIONS AND ACRONYMS
High Pressure Distribution	HPD
High-pressure Distribution Service	HPS
Independent System Operator	ISO
International Border	IB
Interstate Transition Cost Surcharge	ITCS
Joint Recommendation (SoCalGas)	JR
Kern River and Questar	the Pipelines
Kern River Gas Transmission Company and Questar Southern Trails Pipeline Company	Kern River
Lodi Gas Storage	Lodi
Long Run Marginal Cost	LRMC
Low Emission Vehicles	LEV
Marginal Demand Measure	MDM
Medium-pressure Distribution Service	MPS
Monsanto Company	Monsanto
Natural Gas Vehicle	NGV
New Customer Only	NCO
Noncore Commercial and Industrial	Noncore C&I
Noncore Storage Balancing Account	NSBA
Office of Ratepayer Advocates	ORA
Pacific Gas and Electric Company	PG&E
Performance Based Ratemaking	PBR
Power Exchange	PX
Qualifying Facility	QF
Real Economic Carrying Charge	RECC
Real Time Pricing	RTP
reliability must-run	RMR
Residual Load Service	RLS
San Diego Gas & Electric Company	SDG&E
SDG&E/WHA Joint Recommendation	SDG&E JR
Service Line, Regulator, and Meter	SRM
Southern California Edison Company	SCE
Southern California Gas Company	SoCalGas

NAMES	ABBREVIATIONS AND ACRONYMS
Southern California Generation Coalition	SCGC
The Utility Reform Network	TURN
Transition Cost Balancing Account	TCBA
Transition Cost Recovery	TCR
Transmission-only	TLS
Transwestern Pipeline Company	Transwestern
Ultramar, Inc.	Ultramar
Utility Consumers' Action Network	UCAN
Utility Electric Generator	UEG
Western Hub Properties, Inc.	WHP
Western Mobilehome Park Owners Association	WMA
Zone Rate Credit	ZRC

OPINION

I. Summary

In the Southern California Gas Company (SoCalGas) section of this decision we approve a Joint Recommendation sponsored by SoCalGas, the Office of Ratepayer Advocates (ORA) and others which adopts, among other issues: (1) a three-year Biennial Cost Allocation Proceeding (BCAP) period, (2) a throughput forecast of 950.3 MMdth, (3) 75/25 balancing account protection for noncore throughput variation , (4) a transmission resource plan of $32.5 million, (5) the new customer only (NCO) marginal cost method, (6) 50/50 balancing account protection for storage, and (7) a delay in core deaveraging. Rates are reduced by $158.9 million for the core and $50.7 million for the noncore. The average winter monthly residential bill is reduced from $84.75 to $79.19.

In the San Diego Gas & Electric Company (SDG&E) section of this decision we approve a Joint Recommendation sponsored by SDG&E, ORA, and the Utility Consumers' Action Network (UCAN) which adopts, among other issues: (1) a throughput forecast of 480 million therms for former Utility Electric Generator (UEG) customers, (2) a $31 million gas transmission resource plan, (3) the NCO marginal cost method for customer costs, (4) a single tariff schedule for core commercial and industrial customers, and (5) elimination of schedule XGTS. Core rates are reduced $18 million; noncore rates are reduced $18.7 million. The average winter monthly residential bill is reduced from $27.44 to $26.46.

The interstate transition cost surcharge (ITCS)is found to be $59.894 million and allocated $11.559 million to the core and $48.335 million to the noncore. The core fixed cost account (CFCA) is found to be overcollected by $132 million, to be amortized in rates over a one-year period. (This $132 million is included in the overall $158.9 million core rate reduction.) We find that it is in the public interest to adopt a Sempra-wide electric generation (EG) tariff, that is, one that is the same for SoCalGas' EG customers and SDG&E's EG customers. We continue in effect SoCalGas' residual load service (RLS) tariff for not more than one year from the effective date of this decision, or until a replacement peaking rate is adopted, whichever is later.

II. Background

SoCalGas and SDG&E seek to revise rates for gas service effective August 1, 1999, to reflect the allocation among customers of costs of service previously authorized by the Commission for recovery in gas service rates. They also seek to reflect in gas service rates the remaining account balances in various balancing, tracking, and memorandum accounts previously authorized by the Commission.

SoCalGas proposed rates that would reduce total revenue by approximately $204.4 million, or 11.2%, annually, compared to revenue at present rates (October 1998). SDG&E proposed rates that would reduce total gas revenue by $9.3 million or 3.8% annually from present rates (October 1998). The two applications were consolidated for hearing. Twenty three days of public hearings were held before Administrative Law Judge (ALJ) Robert Barnett and the proceedings were submitted September 3, 1999; proceedings were reopened November 11, 1999 to receive briefs on the issue of the appropriate amortization period for the regulatory account balances resulting from reallocation of interstate pipeline surcharges to noncore customers; the proceedings were resubmitted December 20, 1999. The Proposed Decision was timely issued on January 11, 2000.

Eighteen active parties [1] participated in one or more issues and filed briefs. For the sake of brevity this decision will not discuss every argument of every active party, but will cover the salient points made in the briefs.

On January 29, 1999, SoCalGas filed revised testimony, reflecting a revenue decrease of $207.8 million (or 11.4%) as compared to rates effective in October 1998.

Subsequent to the filing of the applications, the Commission issued Resolution G-3247 approving Advice Letter No. 2751 filed on October 15, 1998 by SoCalGas. This resolution approved revisions to SoCalGas' rates effective January 1, 1999 to reflect the amortization of various balancing account balances. The resolution resulted in a decrease of $125.5 million in core revenue and a decrease of $33.0 million in noncore revenue.. On December 16, 1999, the Commission issued Resolution G-3275 approving Advice Letter No. 2847 filed by SoCalGas on September 20, 1999. This resolution approved a refund to SoCalGas' core customers of $100 million, to reflect an overcollection in the CFCA, through a one-time bill credit in the December 1999 billing cycle to eligible core customers.

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[1] Southern California Gas Company (SoCalGas); San Diego Gas & Electric Company (SDG&E); the Office of Ratepayer Advocates (ORA); California Cogeneration Council and Watson Cogeneration Company (CCC); California Industrial Group and California Manufacturers Association (CIG/CMA); Department of General Services (GS); Electric Generator Alliance (EGA); Kern River Gas Transmission Company and Questar Southern Trails Pipeline Company (Kern River); city of Long Beach (LB); Monsanto Company (Monsanto); Pacific Gas and Electric Company (PG&E); Southern California Edison Company (SCE); Southern California Generation Coalition (SCGC); The Utility Reform Network and the Utility Consumers' Action Network (TURN or UCAN); Ultramar, Inc. (Ultramar); city of Vernon (Vernon); Western Hub Properties, Inc. (WHP); and Western Mobilehome Park Owners Association (WMA).

After considering the effect of the two reductions authorized by Commission resolutions, there remain issues regarding tariffs that recover excessive revenue, especially in the ITCS computation; modification of tariffs that would shift costs between core and noncore; elimination of tariffs; consolidation of tariffs; and the reasonableness of various practices of SoCalGas and SDG&E.

ORA estimates that the SoCalGas Joint Recommendation will result in a revenue decrease of approximately $63.9 million for SoCalGas customers, from rates in effect January 1, 2000, in addition to the reductions authorized in the two Commission resolutions. This estimate does not include revenue reductions resulting from ITCS shifts and overcollections in the CFCA not captured in the two Commission resolutions. The differences between SoCalGas and ORA are primarily attributable to the different ITCS amounts allocated to noncore customers.

This decision will first resolve SoCalGas issues and then resolve SDG&E issues. Those issues common to both companies will be resolved in the SoCalGas portion of the decision.

III. The Joint Recommendation

SoCalGas, ORA, TURN and CIG/CMA met to negotiate a mutually acceptable outcome to many of the most contentious issues in this proceeding. These efforts led to the development of the Joint Recommendation (JR) submitted into evidence as Exhibit 169-A (Appendix A). The JR would resolve each of the following issues: (1) the length of the BCAP period; (2) the throughput forecast; (3) the degree of balancing account protection associated with the throughput forecast and any discounting needed to retain load; (4) the transmission resource plan; (5) the marginal cost methodology for each of the four functional categories; (6) the appropriate core reservations for interstate capacity and storage; (7) the level of risk for the unbundled noncore storage program; and

(8) cost allocation issues relating to Hub revenues, the Direct Assistance Program, and certain competitive load growth opportunities.

After negotiations the Joint Recommendation was presented to other parties for their consideration. SDG&E, Chevron, Texaco, and Vernon joined the Joint Recommendation. Three other parties, SCE, SCGC, and WHP, filed testimony opposing all or part of the JR. They generally argue that since they were not part of negotiations and since their positions were not adopted, the JR should be rejected. The JR is offered for the Commission's consideration as an entire package rather than as a series of discrete issues. The parties supporting the JR believe that the package, as a whole, represents a reasonable compromise of the competing interests, is in the public interest, and should be adopted without modification.

While the parties to the JR support its adoption as the preferred outcome on the issues it addresses, each party also litigated, on an independent basis, each of the issues before the Commission.

ORA's brief contains an excellent summary of the JR, which we have used extensively in describing its various elements. We adopt the JR for the reasons stated below.[2]

[2] We cannot emphasize too strongly that our extended discussion of some of the issues resolved by the JR is not meant to indicate a leaning toward one point of view rather than another. The discussion is meant to show the depth of the controversy and the salutary effect of the settlement. We adhere to the principle that a joint recommendation is not precedential. (Cf. Rule 51.8.)

A. Overview of the Joint Recommendation

1. BCAP Period

One of the more basic issues resolved by the JR is the length of the BCAP period. SoCalGas, ORA, and TURN all recommended a three-year period to align the end of the BCAP period with the end of the current Performance Based Ratemaking (PBR) cycle. CIG/CMA and others recommended the traditional two-year period. The JR would adopt a three-year period, January 1, 2000 through December 31, 2002.

2. Throughput Forecast

Another hotly contested issue was the throughput forecast to be used to set rates. Only ORA and SoCalGas presented complete forecasts. SoCalGas based its forecast on a single year, 1999, while ORA used a three-year forecast to coincide with the three-year BCAP period. ORA forecast considerably more throughput for the electric generation class.

In response to a ruling by the ALJ, SoCalGas submitted a revised forecast based on a three-year forecast period. The revised forecast was considerably lower than the single year forecast based upon 1999 throughput. Most of the intervenors supported ORA's higher forecast. The JR would adopt a forecast which is somewhat higher than the forecast contained in SoCalGas' initial showing (932.2 MMdth) and significantly higher than the revised forecast produced in response to the ALJ ruling (896.8 MMdth). The adopted forecast is 950.3 MMdth, which includes 24.9 MMdth added to the noncore demand forecast to account for international border service.

3. Noncore Risk

In conjunction with adopting a higher throughput forecast, the JR would also reinstitute the 75/25 balancing account protection for noncore revenue that was in place prior to the adoption of the Global Settlement for both throughput variation and lost revenue resulting from discounting. ORA, TURN, CIG/CMA and other parties had initially opposed a return to balancing account protection.

4. Transmission Resource Plan

The transmission resource plan is a critical element in calculating transmission marginal costs. The resource plan essentially determines how much investment is needed over the next 15 years to satisfy growth in demand. In its 1996 BCAP, SoCalGas forecast a need to invest $88.5 million over the next 15 years to meet growth in demand. This forecast was adopted by the Commission. In this BCAP SoCalGas has lowered that forecast to $18 million based on a lower forecast of long-term demand growth. ORA and TURN argued that this resource plan was too low and amounted to little more than a manipulation of the long term demand forecast in order to shift costs from the noncore to the core. ORA recommended retaining the resource plan from the last BCAP adjusted downward to account for completed projects. This would result in a resource plan of approximately $77 million. TURN recommended including a single project from the last resource plan, the Adelanto project, which would increase the resource plan to $42 million. CIG/CMA and other noncore interests took the position that even the $18 million plan sponsored by SoCalGas was too high because it was based upon a project, Line 6900, which was more appropriately assigned to SDG&E. They essentially argued for a resource plan which included zero load growth related capital additions over the next 15 years. The JR would adopt a resource plan of $32.5 million which is the half-way point between the resource plan proposed by SoCalGas and the one proposed by TURN.

5. Marginal Cost Methodology

The two major marginal cost issues related to the ORA and TURN proposals are to replace the rental method for calculating marginal customer costs with the NCO method and to include a replacement cost adder for the demand related functions of transmission, distribution, and storage. SoCalGas and other noncore interests opposed both the NCO method and the replacement cost adder. The JR would adopt the NCO method, which is the current method adopted for PG&E, SDG&E, and SCE, while rejecting the replacement cost adder. It would also adopt several other less significant compromises on marginal cost issues including TURN's estimate for the Administrative and General (A&G) loader factor as well as TURN's estimate for medium pressure distribution investment.

6. Core Interstate Capacity and Storage Reservations

SoCalGas proposed increasing the core's interstate capacity reservation from 1044 MMcfd to 1076 MMcfd based upon a forecasted increase in the core's cold year demand forecast. The higher reservation would cost core customers an additional $4 million per year. ORA recommended maintaining the reservation at its current level because of the excess of interstate capacity and the availability of supplies at the California border during periods of peak demand. ORA also recommended eliminating the core's responsibility for ITCS costs largely because of the significant benefits noncore customers have received as a result of SoCalGas' relinquishment of capacity on El Paso Natural Gas Company (El Paso) and Transwestern Pipeline Company (Transwestern), estimated to be in the range of $300-$500 million on a present value basis. Elimination of the core's ITCS responsibility would shift approximately $9 million in ITCS costs to the noncore. TURN supported both of ORA's recommendations, while SoCalGas and noncore interests opposed them. As a compromise the JR would resolve this issue by maintaining the status quo with respect to the core interstate capacity reservation. In addition, the core would continue to be responsible for its historical share of ITCS costs. This outcome has no impact on cost allocation since it simply retains the current allocation.

SoCalGas also proposed increasing the core's storage withdrawal capacity reservation from 1985 MMcfd to 2082 MMcfd based upon its estimate of the core's peak day requirement. ORA recommended retaining the reservation adopted in the last BCAP because of the availability of flowing supplies to meet the difference between the current reservation level and peak day requirements which are expected to occur only once every 35 years. TURN recommended lowering the reservation based on a higher estimate of the amount of flowing supplies available on a peak day. Noncore interests sided with SoCalGas in opposing both the ORA and TURN proposals. The JR would compromise this issue by adopting a withdrawal reservation of 1935 MMcfd. This represents the midpoint between the TURN and SoCalGas positions. Lowering the reservation by this amount would increase the amount of withdrawal capacity available for the unbundled storage program.

7. Unbundled Storage Program

Both ORA and WHP recommended eliminating the balancing account protection applicable to the unbundled storage program in order to level the playing field between the incumbent provider of storage services and potential competitors such as Lodi Gas Storage and Wild Goose. ORA and WHP also recommended granting the utility some pricing flexibility in return for the increased risk. SoCalGas indicated that it was amenable to being placed at risk if certain conditions were met, including some pricing flexibility. However, it recommended resolving this issue in the Gas Industry Restructuring proceeding.

The JR would take some interim steps toward a level playing field. The level of shareholder risk would be increased by reducing the current level of balancing account protection to 50/50. In addition, SoCalGas would be granted some pricing flexibility with a cap equal to 120% of the ceiling reservation charges set forth in its tariffs. The costs allocated to the unbundled storage program would be set at $21 million rather than the fully scaled amount of $32 million. The $21 million that would be allocated to the noncore storage program is close to both the embedded cost of the facilities and the unscaled marginal costs. The $11 million difference would be allocated to the Noncore Storage Balancing Account (NSBA) along with other stranded costs. The balance in the NSBA would be recovered from all customers on an equal-cents-per-therm basis.

8. Cost Allocation Associated with Core Deaveraging, Hub Revenues, the Direct Assistance Program, and Incremental Load Growth Opportunities

The JR would also resolve a number of other cost allocation issues including core deaveraging, the allocation of Hub Revenues, the recovery of Direct Assistance Program costs and the treatment of incremental load growth resulting from shareholder funded discounts.

a. Core Deaveraging

In each of the last two BCAPs, the Commission has made progress in eliminating the effects of averaging residential and commercial rates. To date, 75% of the effects of averaging have been removed from commercial rates. Both SoCalGas and ORA proposed fully eliminating the effects of averaging during this BCAP period. This would shift an additional $28 million in costs from commercial to residential customers. TURN proposed maintaining the status quo arguing that SoCalGas was already well ahead of other utilities in eliminating the effects of averaging. The JR adopts the TURN recommendation to maintain the status quo.

b. Hub Revenues

Currently revenues generated from SoCalGas' Hub services are used to reduce the gas costs recorded in the company's gas cost incentive mechanism (GCIM). This is consistent with the finding in the last BCAP that core flowing supplies were essential to the provision of Hub services. (D.97-04-082, pp. 82, 175.) SoCalGas proposed to continue that treatment in this proceeding while SCGC recommended removing these revenues from the GCIM and allocating them to all customers on an equal percentage of marginal cost (EPMC) basis. The JR would continue the current practice of crediting the revenues to the GCIM. This is the same treatment adopted in D.97-06-061 approving the GCIM mechanism.

c. Direct Assistance Program Costs

SoCalGas proposed allocating $18 million in Direct Assistance Program (DAP) costs to residential customers. TURN recommended allocating these costs in the same fashion as CARE costs, equal-cents-per-therm. An equal-cents-per-therm allocation would shift approximately 60% of these costs, or $10.8 million, to noncore customers. The JR would adopt the SoCalGas position.

d. Incremental Load Growth

The final cost allocation issue addressed by the JR is the SoCalGas proposal to exempt from the cost allocation process for a five-year period incremental growth associated with shareholder funded discounts under the state sponsored Red Team economic development program and the Commission approved Rule 38 program. Normally, additional load from discounted contracts entered into during one BCAP period would be reflected in the throughput adopted in the following BCAP thereby spreading the benefits of the increased load to all ratepayers. ORA opposed this proposal arguing that the move from a two to a three-year BCAP represented a sufficient increase in shareholder incentives. The JR would adopt the SoCalGas position.

B. Adequacy of Representation

WHP argues that the JR must be rejected because WHP, "a major stakeholder" (WHP's characterization), was not represented at the negotiating sessions which led to the JR. SCE and SCGC make much the same argument as WHP. This argument is without merit.

First, WHP's (or any party's) position could have been rejected whether or not WHP was at the negotiating table. Second, WHP was given the opportunity to comment on the JR, seek to modify the JR, and join the JR. It chose to oppose and presented evidence in opposition. We are not persuaded by its evidence.

While not all parties were invited to the table, we believe the wide range of interests were adequately represented and, as a consequence, the JR represents a fair outcome. We agree with ORA's argument that cost allocation is a zero sum game, and that this proceeding is largely a dispute between core and noncore interests over how to apportion the revenue requirement pie to different customer classes. It is clear that the parties to the JR represent many if not all of the various customer groups and other entities affected by the issues addressed by it. SoCalGas represents not only the interests of its shareholders, but also the interests of all its customers, including, but not limited to, the interests of noncore customers. ORA represents the interests of all ratepayers. TURN represents residential and small commercial ratepayers. CIG/CMA represents a host of commercial and industrial interests, including members of the G-30 tariff class which has a distribution segment, and members of the G-50 tariff class. SDG&E and Vernon are wholesale customers of SoCalGas. Chevron and Texaco are large industrial and electric generation customers. This broad spectrum of interests validates and buttresses the reasonableness of the JR.

WHP strongly opposes the JR. It recommends that the Commission reject the "All Other Storage Issues" provisions of the JR; reject the transmission resource plan of the JR; eliminate the NSBA; and change the long-run marginal cost (LRMC) method used in the JR. WHP complains that it was left out of the negotiations which led to the JR; that the JR made fundamental changes to the structure of the storage market "without involving major stakeholders in the discussions leading to the recommended market changes." (WHP O.B. p. 6.)

WHP claims to be a "major stakeholder." That it is a stakeholder, in a sense, is plausible; but that it is a major stakeholder is nonsense. It is not a customer of SoCalGas, it contributes nothing to SoCalGas' revenue requirement, if it succeeds in raising SoCalGas' storage rates it will attempt to take SoCalGas' customers, thereby placing the burden of satisfying SoCalGas' revenue requirement on the remaining core and noncore customers. It is an active party and a competitor. The stake of an outsider is small in comparison to those who have to pay the gas bills. Yet, WHP's interest was represented, in part. Both WHP and ORA recommended eliminating balancing account treatment for noncore storage services while simultaneously granting the company some pricing flexibility. SoCalGas, on the other hand, recommended deferring the issue to Gas Industry Restructuring (GIR). The JR clearly moves in the direction recommended by ORA and WHP.

SCGC and SCE do pay gas bills and are stakeholders. However, their assertion that the JR is fundamentally flawed because they were not at the bargaining table and their interests were underrepresented is without merit. As noted above, we believe a reasonable cross-section of SoCalGas' customers were represented. Further, SCGC and SCE were offered the opportunity to have the parties to the JR consider their issues and interests. But most importantly, parties opposed to the JR were given ample opportunity to refute on the record and in briefs each and every issue resolved by the JR. There is no requirement that all parties in a proceeding must be included in a joint recommendation. Such a requirement would be granting a veto to any party, which is clearly not in the public interest.

We believe the opponents misconceive the nature of a joint recommendation. A joint recommendation, such as the one presented here, is a compromise of positions of some of the parties, which, by its very nature, has no precedential value. It is of assistance to the Commission to the extent that the parties to the recommendation are knowledgeable and have vested interests in the outcome. In this instance it is the reasonableness of outcome that persuades us to adopt the JR.[3] The point of a compromise is to avoid deciding the merits of each individual contested issue. Given the variety of views on all issues, we cannot say that an issue by issue determination by the Commission would result in a more accurate prediction of costs, allocations, and rates, than that which is derived from the JR. What we can say is that the JR gives us confidence that major stakeholders with vested interests think it is reasonable.[4] Our analysis of the JR leads to the same conclusion.

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[3] We do not adopt all of the introductory language of the JR. See Section XXI for a discussion.

[4] D.97-06-060 reminds us that "excluding active parties from discussions about proposals which are eventually brought before this Commission only weakens the recommendation. . . ." (At p. 30.) We agree with this proposition and acknowledge that

Footnote continued on next page

We note that a number of the issues resolved by the JR also have been raised in our GIR proceeding (I.99-07-003). Because the JR is non-precedential, by approving it we are not limiting the Commission's consideration of those issues in the broader context of the GIR proceeding.

The remaining sections of this decision present an overview of the parties' litigation positions and, where relevant, the manner in which the JR is the preferred solution.

IV. Length of Periods

A. Length of BCAP Period

Following the initial restructuring of the gas industry in May, 1988, the Commission elected to revisit gas cost allocation and rate design issues annually (D.89-01-040, 30 CPUC2d 576,618). However, it soon became apparent that annual cost allocation proceedings for each of the three major gas utilities were administratively burdensome. The Commission then moved to biennial cost allocation proceedings (D.90-09-089, 37 CPUC2d 583, 626) but, because of circumstances unique to each case, rates often remained in place for periods greater than 24 months.

In this case, SoCalGas, SDG&E, ORA, and TURN are all proposing that rates from this proceeding be in place until the end of 2002, a period of three years assuming an end-of-the-year decision. This would synchronize the end of the BCAP with the end of both the SoCalGas and SDG&E PBR proceedings. The

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not all active parties participated in discussions leading up to the JR. But all active parties had ample time to comment on, criticize, and cross-examine prior to its adoption.

parties also recommend that the next cost allocation and PBR proceedings be consolidated into a single proceeding.

SCGC and CIG/CMA oppose a BCAP period longer than the traditional two years. They argue that extending the forecast period beyond the traditional 24-month period introduces significant uncertainty into the forecast. Some of that uncertainty includes determining where new power plants will be sited, how recently deregulated power plants will operate, and if and when new bypass pipelines will appear. A three-year period increases the risks associated with fluctuations in load over forecast amounts. Loads higher than forecast mean ratepayers paid too much; loads lower than forecast mean the utility will not recover its revenue requirement.

B. Length of the Forecast Period

One of the more controversial issues is the proposal by both SoCalGas and SDG&E to use a forecast of 1999 throughput for the entire BCAP period. ORA and other parties oppose this proposal and instead recommend that the forecast period match the BCAP period.

SoCalGas puts forth several reasons justifying its proposal to use a single year forecast. First, using a single year forecast eliminates the need to litigate forecasts for the years 2000-2002. Second, use of a 1999 forecast is intended to provide upside potential to offset the downside risk of discounting and loss of load. Those opposed to a single year forecast believe it has the same infirmity as the three-year BCAP: fluctuations make it uncertain and risky.

C. Impact of the Joint Recommendation

Adoption of the JR will result in a reasonable compromise of the debate over the appropriate length of the BCAP period and whether the forecast should be based on a single year or multi-year forecast. Under its terms, BCAP rates would be in place for three years and rates would be based upon an agreed upon forecast which is a compromise between SoCalGas' single year forecast and the higher ORA forecast based upon a three year average. The reasonableness of the forecast is addressed below.

V. Throughput

A. Econometric Throughput

Both ORA and SoCalGas used econometric models to forecast throughput for residential, commercial core (G-10), industrial core (G-20), and commercial/industrial noncore (G-30) customers. The table below sets forth the ORA and SoCalGas direct showing forecasts for each of these classes as well as the forecasts for the relatively new gas air conditioning and gas engine customer classes. At the request of the ALJ, ORA and SoCalGas also prepared forecasts based on the forecast period of 1999-2001. Those forecasts are also included in the table. The analysis which follows is generally based upon each party's initial showing, the ORA forecast for the years 2000-2002, and the SoCalGas forecast for 1999.

TABLE 1

ORA and SoCalGas Econometric Demand Forecasts (MMdth)

Class	ORA	ORA	SoCalGas	SoCalGas
Years	2000-2002	1999-2001	1999	1999-2001
Residential	263.02	261.20	254.70	257.90
G-10	78.689	78.25	79.10	79.90
G-20	4.70	4.68	4.70	4.70
Gas Engine	1.60	1.60	1.60	1.60
Gas AC	0.12	0.12	0.12	0.12
Total Core	348.00	345.90	340.20	344.30
Comm/Ind G-30	147.00	146.40	146.90	141.50

ORA and the company disagree on the forecasts for residential demand, commercial core (G-10) demand, and commercial/industrial noncore (G-30) demand. For the residential class, ORA forecasts an average throughput over a three year BCAP period (2000-2002) of 263.02 MMdth while the company forecasts a 1999 demand of 254.70 MMdth, a difference of 3.3%. ORA forecasts G-10 demand of 78.689 MMdth while SoCalGas forecasts demand at 79.107 MMdth, a difference of less than 1%. For G-30 load, ORA forecasts a demand of 147.0 MMdth while SoCalGas forecasts a demand of 146.9 MMdth, again a difference of less than 1/2%. These differences are the result of differing assumptions regarding the length of the forecast period and the number of heating degree days. ORA relied on a three year forecast of demand for the period 2000-2002 while the company used a forecast of throughput for a single year, 1999.

The second major difference results from different estimates of heating degree days (HDD) which are a key factor in explaining historic gas demand, particularly residential demand. The majority of California's gas and electric utilities rely on historical averages to forecast heating and cooling degree days. ORA followed this practice and based its estimate on a 20-year average with a resulting estimate of 1358 heating degree days. SoCalGas proposes to move away from the traditional approach and bases its estimate on a trend analysis. The trend analysis produces an estimate of 1,222 heating degree days. SoCalGas' lower heating degree day estimate has the effect of increasing rates to all customers, raising residential rates by 4%, wholesale rates by 3%, and noncore rates by approximately 1%.

SoCalGas justifies the trend analysis on the ground that southern California has been experiencing a warming trend over the past 20 years which isn't captured through a 20-year average. ORA asserts that the 20-year average reasonably captures any warming trend since it results in an HDD estimate which is 10% lower than the estimate used in the Global Settlement. ORA believes that the SoCalGas model goes too far in producing an estimate that is almost 20% lower than the estimate used in the Global Settlement. SCGC has serious doubts about the accuracy of the linear trend analysis used by SoCalGas as it produces results significantly at variance with traditional methods and raise rates for all customers.

B. Non-Econometric Throughput

Eight categories of throughput on the SoCalGas system are forecast non-econometrically: (1) exchange contracts; (2) enhanced oil recovery (EOR); (3) wholesale (excluding SDG&E electric generation (EG)); (4) SoCalGas EG; (5) cogeneration; (6) SDG&E EG; (7) Distribuidora de Gas Natural de Mexicali (DGN); and (8) Rosarito. The following table compares the ORA and SoCalGas forecast for each of these categories for a BCAP period which extends through the year 2002. At the request of the ALJ, ORA and SoCalGas also prepared a forecast based on the years 1999-2001. These forecasts are included in the table.

TABLE 2

(MMdth)

CUSTOMER CLASS	ORA		SoCalGas	
	2000-2002	**1999-2001**	**1999**	**1999-2001**
Exchange	9	9	9	9
EOR	49	49	49	49
Wholesale	94	90	94	95
EG	230	215	202	181
Cogeneration	85	85	84	77
SDG&E EG	48	44	44	37
DGN	5	5	3.6	4
Rosarito Adjustment	25	15	0	
Total	545	512	485.6	452

As can be seen from the table, the major areas of dispute relate to the estimates for EG and cogeneration throughput on the SoCalGas system and EG throughput on the SDG&E system. While the table shows a significant difference between ORA and SoCalGas with respect to Rosarito throughput, this is the result of different ratemaking recommendations. SoCalGas proposes to exclude Rosarito throughput from the cost allocation process and instead recommends a revenue crediting mechanism. ORA, on the other hand, recommends including the throughput in the cost allocation process in order to develop a full cost of service rate.

Two factors account for the differences between ORA and SoCalGas. First, SoCalGas proposes to use a single year's forecast, 1999, for the entire BCAP period while ORA proposes using the average of a three year forecast for period

2000-2002. Second, ORA used a more recent forecast of electric demand. As an input assumption, ORA used the California Energy Commission's (CEC) Outlook 1998 forecast of electric demand for the years 2000-2002. ORA also used SoCalGas' forecast of gas prices for the same period even though recent experience indicates that the forecasts may be on the high side.

SoCalGas claims the ORA forecast is too high because it failed to take a number of relevant factors into account. Accounting for off-system generation, NOx emissions, and Qualifying Facility (QF) buyouts, SoCalGas provided a total EG forecast (SoCalGas and SDG&E) for the period 2000-2002 of 233 MMdth. This is lower than the ORA forecast of 324 MMdth, and is considerably lower than the company's own 1999 forecast for 300 MMcfd. SoCalGas reduces the throughput even further by assuming 13 MMdth is lost to bypass in the year 2000 and 21 MMdth is lost to bypass in 2001.

ORA contends that SoCalGas' forecasts are contrary to CEC forecasts which show EG gas demand increasing over the 2000-2002 period rather than decreasing. The CEC, in its 1998 Natural Gas Outlook, projects EG demand similar to SoCalGas for 1999. However, it forecasts EG demand growing by 13% on average for the period 2000-2002. A 13% increase over SoCalGas' 1999 forecast of 256 MMdth yields a forecast of 289 MMdth. This is consistent with the ORA forecast of 286 MMdth.

C. Revenue Risk

For the past five years, SoCalGas has been at risk for both noncore throughput variations and discounting. SoCalGas proposes to continue that practice over the upcoming BCAP period provided that its 1999 forecast of throughput is adopted. Given the forecast of EG throughput contained in its presentation, SoCalGas admits that its 1999 forecast is a "stretch" target which balances risk and reward. It takes the position that if a higher throughput is adopted it should be protected from the risk of a three year forecast through reinstitution of the 75/25 ratepayer/shareholder balancing account protection that existed prior to the Global Settlement.

ORA argues that the SoCalGas proposal is skewed in favor of shareholder rewards. SoCalGas' policy witness acknowledges that the 1999 forecast is designed to provide upward earnings potential. This is also evidenced by both the higher ORA forecast using either a 1999-2001 or 2000-2002 period and the CEC's estimate for EG gas demand for the 2000-2002 period.

D. Gas Price Forecast

In past BCAPs, the gas price forecast served an important role since it was used to set the core procurement rate. Core gas prices are now revised monthly for both SoCalGas and SDG&E to track market conditions. Because of this regulatory change, the gas price forecast is less significant. Its use now is as an input to the econometric and production cost models used to forecast core and noncore throughput. After reviewing the model's sensitivity to price changes, ORA relied on SoCalGas' gas price forecasts for the years 2000-2002.

E. Impact of the Joint Recommendation

The JR would resolve the throughput issue by adopting a higher level of throughput than that proposed by SoCalGas. It would also reinstitute 75/25 balancing account protection for noncore revenue. This is a reasonable compromise given the litigation positions of the parties. ORA and other parties take the position that SoCalGas' forecast is too low while SoCalGas takes the position that the ORA forecast is too high. The JR adopts a forecast considerably higher than the one contained in SoCalGas' rebuttal testimony. The 75/25 balancing account is reasonable since it will continue to place shareholders at some risk for discounting while protecting shareholders and ratepayers in the event the adopted forecast is significantly off the mark.

VI. Long-Run Marginal Costs (LRMC)

A. Summary

Since the inception of LRMC ratemaking for gas utilities, there has been an ongoing debate over the appropriate methodology for calculating both customer marginal costs and marginal costs for the demand related functions of distribution, transmission, and storage. That debate continues in this proceeding.

Both ORA and TURN recommend replacing the existing "rental method" for calculating customer marginal costs with the "new customer only" method. While the Commission originally adopted the rental method in its LRMC policy decision, that method has subsequently been replaced by the NCO method for every major gas and electric utility except SoCalGas.

The original LRMC policy decision found that the capital component of the demand related marginal costs for distribution, transmission, and storage should be based solely on the incremental investments needed to meet growth in demand. In its testimony in the 1995 PG&E BCAP, ORA identified several problems with the adopted methodology and recommended modifying it by including not just the investments needed to serve demand growth, but also the investments needed to maintain system reliability. The Commission adopted the proposed "replacement cost adder" as a "necessary refinement" to the existing methodology. (Re Pacific Gas and Electric Co., D.95-12-053, 63 CPUC2d 414, 433.) Both ORA and TURN have recommended adopting the replacement cost adder in this proceeding for both SoCalGas and SDG&E.

In addition to the above policy recommendations, ORA also takes issue with some of the more technical aspects of SoCalGas' marginal cost estimates. Each of these issues is addressed below.

B. NCO/Rental Method

In this case, as in each cost allocation proceeding since 1992, the Commission is faced with a choice between the rental method and the NCO method for calculating customer marginal costs. The two approaches are significantly different in both concept and outcome.

The NCO and rental methods both begin by estimating the cost of installing the service line, regulator, and meter (SRM) at a customer's premises. The NCO method assumes that the SRM facilities that have been installed for existing customers are a sunk cost. Consequently, only the SRM investments for new customers anticipated over the BCAP period are considered in determining marginal customer costs. A second component is then added to the SRM capital estimate to reflect the replacement of existing SRM facilities due to wear and tear. Finally an annual O&M cost is applied to all customers.

The rental method, like the NCO method, begins with an estimate of SRM costs. This estimate is then annualized using a real economic carrying charge (RECC). The resulting "rent" is then charged to all customers. The same O&M component used in the NCO method is also applied to all customers. In essence, the rental method treats all customers as new customers and requires them to pay a rental fee to gain access to the system.

The two approaches result in significantly different marginal customer costs. For example, the marginal cost for SoCalGas' residential customers is $75 under the NCO approach and $120 under the rental approach (1999$). For commercial/industrial (G-30) noncore customers the marginal cost is $5,274 under the NCO method and $8,852 under the rental method. On a cost allocation basis, the rental method allocates $31.5 million more to the core than the NCO method.

The proponents of the NCO method claim that the rental method is based upon an inappropriate theoretical foundation: a hypothetical competitive rental market with no opportunity to pay hookup charges or purchase the equipment. As a consequence, the rental method significantly overcharges customers.

The proponents of the rental method claim that it is the NCO method which is fatally flawed because it is the rate of growth of a particular customer class which drives the marginal cost estimates. As an example, they point to the impact that the NCO method had on the gas engine class following our initial adoption of the NCO method in SoCalGas' last BCAP. Because the NCO method resulted in an 80% increase for this class, we elected to retain the rental method (D.97-08-062). These proponents believe the NCO method is theoretically incorrect, is not based on cost causation, and sends inaccurate price signals.

Until this proceeding, ORA has been a consistent advocate of the rental method. However, ORA has elected to not pursue adoption of the rental method in this case given the long line of Commission precedent stating a preference for the NCO method. As noted below, we have now considered the arguments in favor and against the NCO and rental methods on several occasions and have consistently opted for the NCO method. There is nothing unique in this case justifying a deviation from that long line of precedent.

In the original LRMC decision, we were faced with choosing between the NCO method proposed by TURN and PG&E and the rental method proposed by the other utilities and the Division of Ratepayer Advocates (DRA) (ORA's predecessor). We opted for the rental method observing that it had been in use for electric utilities for the past four years. At the same time, we noted that the NCO method was being actively considered for electric ratemaking purposes in PG&E's then pending general rate case. (Re Rate Design for Unbundling Gas Utility Services, D.92-12-058 47 CPUC2d 438, 463.) In fact, we adopted the NCO method for electric ratemaking purposes on the same day. (Re Pacific Gas and Electric Co., D.92-12-057, 47 CPUC2d 143, 293.) One of DRA's arguments against the NCO method in the PG&E GRC was that it was unstable in that the marginal costs were driven by the rate of growth of a particular class. That argument, which is also being made in this proceeding, was rejected.

The issue was revisited in the 1995 PG&E BCAP with TURN and PG&E recommending a revised NCO methodology. Under the revised method, a component was added to the marginal cost to reflect the replacements of existing SRM facilities due to wear and tear. ORA continued to support the rental method while acknowledging that the proposed revision to the NCO method was an improvement. We adopted the NCO proposal noting that it "provides a better measurement of the future costs the utility will incur to serve its customers and therefore should be adopted." (Re Pacific Gas & Electric Co., D.95-12-053, 63 CPUC2d 414, 437.)

The issue was revisited in SCE's 1996 general rate case. We began our analysis by noting that its goal was to establish marginal costs that simulate pricing in a competitive market. (Re Southern California Edison, D.96-04-050, 65 CPUC2d 362, 403.) We went on to note that:

> Parties opposing the NCO method argue that marginal costs should not distinguish between existing and new customers or vary according to the growth rate in new customers within a class. They argue that all customers should see the same per unit marginal costs, consistent with pricing in a competitive market. They point out that other components of marginal cost demand costs do not distinguish among new and existing customers in this manner. In their view,

> the methodology for calculating marginal customer costs should similarly apply an annualized charge to all customers.

We then proceeded to analyze and reject each of these arguments finding: (1) that the NCO method fully comports with marginal cost pricing theory; (2) the rental method is premised on an assumption concerning opportunity value that does not hold for customer hookups; and (3) the rental method does not produce a competitive price for customer hookups and, in fact, significantly overstates the price that would prevail in a competitive market (*Id.*, pp.403-404) In short, we considered and rejected each of the arguments being made in this proceeding.

Finally, the issue was revisited yet again in SoCalGas' 1996 BCAP with both TURN and SDG&E proposing the NCO method and SoCalGas, ORA, and other intervenors supporting the rental method. The NCO method was again attacked on grounds that the rate of growth was the primary driver of the allocation and that small, rapidly growing customer classes could experience rate volatility. We adopted the NCO method finding that:

> The NCO method is preferable to the rental method as it improves both the price signal sent to the customer and costing accuracy. Parties have not presented any new evidence in this proceeding that causes us to change the conclusion we reached in PG&E's last BCAP, D.95-12-058, or Edison's GRC, D.96-04-050. (D.97-04-082, Slip Opinion, p. 59.)

SoCalGas subsequently filed a petition to modify D.97-04-082 noting that application of the NCO method to the small, rapidly growing gas air conditioning and gas engine classes resulted in rate shock. In response to the petition, TURN made several proposals to ameliorate the rate shock. However, since these proposals were not a part of the record in the proceeding, we elected to retain the rental method for SoCalGas. At the same time, we continued to apply the NCO method to SDG&E and further indicated our continuing preference for the NCO method. (D.97-08-062, p. 4.)

SoCalGas and other proponents of the rental method continue to point to the impact of the NCO method on small rapidly growing classes as a reason for rejecting it. However, based on the evidence of record, that argument is now moot since the growth rates of the gas air conditioning and gas engine classes have now subsided. As indicated by SoCalGas' workpapers, those classes grew rapidly in the first few years after they were created. However, the growth rate has now flattened out and is expected to remain relatively flat through the BCAP period. The gas air conditioning class shows a zero growth rate, while the gas engine class shows 7.7% growth rate. For the air conditioning class, the NCO method produces marginal costs which are lower than those resulting from the rental method. For the gas engine class the NCO method produces marginal costs that are only 8% higher. In short, rate shock is no longer a viable basis for rejecting the NCO method. In any event, we have numerous tools at our disposal, such as rate caps, for preventing rate shock. We agree with ORA that the potential impact of the NCO method on small, and rapidly growing classes is an insufficient basis for rejecting the methodology given that the argument has been considered and rejected on several prior occasions.

C. Replacement Cost Adders

The Commission's initial LRMC policy decision adopted a methodology for estimating marginal capital costs for the demand related functions of transmission, distribution, and storage that focused solely on the incremental investments needed to satisfy demand growth over the planning horizon while maintaining the appropriate level of reliability. The methodology gave no consideration to the capital investments required over the planning period to replace equipment which was either worn out or which had to be upgraded to satisfy environmental requirements.

ORA identified a number of problems with this methodology in PG&E's 1995 BCAP. First, the practice of ignoring the replacement of worn out facilities for the demand functions was inconsistent with both the rental method and NCO methods of calculating marginal customer costs. Second, ignoring these "opportunity costs" could either prevent capital recovery for these long-life investments or shift the cost responsibility to captive customers. Third, the methodology artificially lowered the marginal costs. Since the utilities were authorized to discount down to LRMC to meet potential competition from bypass pipelines, an artificially low marginal cost for a function such as transmission had the potential to stifle competition. To remedy this problem, DRA recommended that the Commission adopt a "replacement cost adder" to account for capital additions needed to replace worn out facilities or to satisfy environmental requirements. Our decision adopted the DRA recommendation. (Re PG&E, 63 CPUC2d 414, 432.)

SoCalGas and others argue that there is no need for a replacement cost adder. In response to ORA and TURN arguments that the 1995 PG&E BCAP included a replacement cost adder, they cite the 1996 SoCalGas BCAP decision which states "we do not view that decision as precedential because it was based solely on the circumstances surrounding PG&E's resource plan in that case." (D.97-04-082, p.49.) They also argue that including a replacement cost adder in the existing LRMC methodology would result in a double counting of replacement costs, and that the replacement costs considered by ORA and TURN are not actually marginal costs.

In SoCalGas' last BCAP, ORA and TURN recommended that the replacement cost adder adopted for PG&E be applied to SoCalGas and SDG&E.

However, we rejected the replacement cost adder because it was precluded by the Global Settlement:

> While pure economic theory argues for inclusion of replacement costs in a true long run marginal cost methodology, the Global Settlement does not allow a methodology change of this magnitude which goes beyond a mere "refinement" and results in a significant cost shift not envisioned by the signatories to the Global Settlement. Even if the Global Settlement could be overlooked, which this decision finds if cannot, the Commission should more properly consider a change of this magnitude in a reexamination of our natural gas strategy and policies. (*Id.*, p. 49.)

We said that while the replacement cost adder had been adopted for PG&E, we did not view that case as precedent because it was based solely on the circumstances surrounding PG&E's resource plan. With the Global Settlement no longer an issue, the parties opposing the replacement cost adder argue that the PG&E BCAP decision should not be considered a precedent and that the issue should be deferred to the Natural Gas Strategy proceeding. The record evidence in this case indicates that they are wrong on both counts. The PG&E BCAP decision essentially agreed with ORA's generic analysis of the problems with the existing methodology. Since the ORA analysis was generic, it is not surprising that each of the problems we identified with the PG&E resource plan is also present with the SoCalGas resource plan.

We first found that PG&E's resource plan did not measure the entire quantity of service being provided nor did it measure all changes in output. This is also true of the SoCalGas plan since it fails to include investments needed to replace worn out facilities thereby maintaining the level of reliability (i.e., service provided). As noted by TURN, in both the PG&E BCAP and this proceeding, an investment in replacement facilities is a change in cost to prevent a negative change in output. By failing to consider replacement costs, the SoCalGas resource plan fails to measure this change in output. The second problem with the PG&E resource plan was that it measures a shorter time horizon than the long term. The SoCalGas and SDG&E resource plans have the same problem as the PG&E plan since all three are based on a 15-year planning horizon. (Re Pacific Gas and Electric Co., D.95-12-053, 63 CPUC2d 414, 430.) The third problem with the PG&E plan was that it reflected only a small portion of the forward looking capital costs it would spend in providing service. The same is true of the SoCalGas resource plan. SoCalGas proposes spending $18 million over a 15-year period, or less than $1 million per year on growth related investments. At the same time, its expenditures on replacements over the 1994-1998 time frame averaged over $12 million per year.

We concluded our discussion of the replacement cost issue in the PG&E BCAP decision by noting a number of negative consequences associated with the understating of marginal costs.

- it would send an improper price signal to customers
- it would permit PG&E to subsidize potentially competitive sectors of its business
- it would provide less incentive for economic efficiencies
- it would cause revenue responsibility to unfairly shift to captive customers, and perhaps most importantly
- it would allow PG&E to collect revenues in a manner not available to firms subject to competitive market forces. Re Pacific Gas and Electric Co., *supra*, p. 433.)

None of the problems associated with understating marginal costs by excluding replacement investments are unique to PG&E. These negative consequences flow equally to the ratepayers of SoCalGas and SDG&E. In summary, all of the marginal cost related problems we identified with PG&E's plan, as well as the negative consequences that flow from that plan, are present in this case.

The parties opposing the replacement cost adder continue to argue that this issue is more properly addressed in the GIR proceeding, R.98-01-011. While we may have viewed the GIR as an appropriate forum for this issue at the time we issued the BCAP decision in 1997, the issue was never actively considered and the rulemaking has now been closed. (D.99-07-015, p. 146.) Furthermore, it was not one of the issues identified for consideration in the upcoming cost/benefit phase of the proceeding. In short, this issue never found a home in the GIR. Since this is the type of cost allocation issue which has been routinely considered in past BCAPs, including the PG&E BCAP which adopted the replacement cost adder, it is appropriately addressed here.

D. Customer Costs

We must adopt an estimate of the costs associated with installing SRM regardless of which methodology, rental or NCO, is adopted. ORA used SoCalGas' SRM data and a five year historical average of customer growth to develop its marginal customer cost estimates.

The NCO methodology adopted for PG&E includes a replacement cost component to reflect the replacement of existing customer services as they wear out. ORA used five years of historical data to develop a replacement rate. For meters and service lines, the replacement rate recommended by ORA is approximately 2% and 0.5% respectively. The ORA estimate also considers that 50% of the meters are refurbished and the cost of replacing service lines is twice as expensive as new installations.

E. Wholesale Rates

Long Beach continues to take issue with the use of the marginal cost methodology for purposes of allocating costs to wholesale customers such as itself. It continues to request that costs be allocated to wholesale customers on the basis of embedded costs, yet it presents no cost studies showing the results of an embedded cost allocation. As a fallback, it requests that the EPMC scaler not be applied to wholesale customers because it reflects costs not directly attributable to wholesale customers. Long Beach has raised these concerns on two prior occasions and lost both times. (D.94-12-052 58 CPUC2d 306, 337; D.97-04-082, Slip Opinion, p. 63.) The recommendation is rejected again.

F. Distribution Marginal Costs

The Commission has adopted a linear regression methodology for calculating distribution marginal costs which relies on 10 years of historical data and five years of forecasted data. In the model, 15 years of cumulative investment is regressed against cumulative incremental load. SoCalGas has used this approach in calculating marginal costs for both its medium and high pressure distribution systems.

Both ORA and TURN are of the view that the forecast of distribution investments for the period 1998-2002 is unreasonable and should not be used in estimating marginal costs. ORA proposes taking a five year historical average and applying a 3.75% annual growth rate to derive a forecast of investments for the period 1998-2002. TURN proposes two alternatives: (1) a regression using the entire 15-year period but assuming a constant medium pressure distribution cost per customer for 1998-2002 equal to the 1993-1997 costs; or (2) a regression based on just 10 years of historical data. Of the two alternatives, TURN prefers the first. A comparison of SoCalGas' distribution marginal costs and those of ORA and TURN are set forth in the following table. To place the estimates on an equal footing, the replacement cost adder has been removed from the ORA and TURN estimates.

TABLE 3

DISTRIBUTION MARGINAL COSTS WITHOUT REPLACEMENT COST ADDER ($ 1999)

	SoCalGas	ORA	TURN
MP $/Mcfd	97.6561	86.1939	82.7713
HP $/Mcfd	0.75907	0.6923	0.6876

Any of the three alternatives presented by ORA and TURN is preferable to the SoCalGas estimate since, as noted below, its forecast of investments for the period 1998-2002 is simply unreasonable.

The historical distribution investments for the period 1993-1997 were $28, $18, $23, and $17 million, respectively, or an average of $21.5 million per year. For 1998 SoCalGas forecasted investments of $36 million and expected this estimate to escalate at a rate of 4% per year through 2002. However, the actual investments experienced in 1998 were only 50% of the forecast, or approximately $18 million. Put another way, the actual investment for 1998 was less than the historical average on which ORA relies, indicating that the ORA recommendation of using the 1993-1997 average and escalating it at a rate of 3.75% is reasonable.

Another indication that the SoCalGas forecast of investments is too high, is the fact that the significantly higher investment forecast is not matched by a significant increase in load growth. Indeed, the company's projected 1998 peak month and peak day demand were either lower, or about the same level, as that experienced over the last five years.

SoCalGas downplays the lack of growth in peak demand by claiming that the number of new customers, rather than peak demand, is the main driver of new investments. Over the forecast period the average number of new customers per year is 51,768 or 38% higher than the 1993-1997 average. Even if this is the case, it doesn't justify the high level of forecasted investments. In the last BCAP, SoCalGas forecasted an average customer growth rate of 54,000 customers per year. This previous forecast, which was higher than the current one, was accompanied by an investment forecast of only $23 million per year. In other words, in the last BCAP, the company was forecasting even greater customer growth, yet the investment forecast was more in line with the historical average on which ORA is relying. Furthermore, even that forecast proved to be too high, with the actual investments for the period 1993-1997 averaging only $21.5 million. In sum, there is absolutely nothing supporting a virtual doubling of the distribution investments for the 1998-2002 period. TURN's recommended adjustments to this forecast are reasonable.

G. Impact of the Joint Recommendation

The JR would resolve each of the issues addressed above except for the issue of whether Long Beach should continue to be subject to LRMC ratemaking. The parties agree to the use of the NCO method for calculating marginal customer costs. The parties also agree on the precise manner in which the methodology should be implemented.

First, the NCO method should be implemented without a replacement cost adder. This is consistent with the parties' agreement to exclude the replacement cost adder in calculating demand related marginal costs. As ORA noted in its testimony, the replacement cost adder should either be included for all functions or excluded for all functions in order to achieve methodological consistency. Second, the parties agree to use TURN's RECC factor and A&G loading factor in developing the customer marginal costs. SoCalGas had already agreed to TURN's adjustment to the A&G loader in its rebuttal testimony. Third, the parties agree to SoCalGas' treatment of developer contributions. Finally, the parties agree that the gas engine transportation rate will be set at SoCalGas' proposed rate of $0.20384 per therm. This agreement resolves the issue over the impact of the NCO method on new customer classes that experience significant growth in the early years. In effect, the JR would cap the rate to avoid rate shock. This is consistent with TURN's recommendation on this issue as well as past Commission practice. The shortfall of approximately $1 million would be allocated to other core customers on an EPMC basis.

For marginal demand related costs, the parties agree to exclude the replacement cost adder. Adoption of the replacement cost adder in a manner consistent with the PG&E BCAP decision would shift approximately $7 million to the noncore. The JR would also adopt TURN's recommendation regarding medium-pressure distribution marginal costs. While this would shift $1.6 million to the noncore, this amount is considerably less than what would occur if ORA's estimate was adopted.

The two major components of the marginal cost package described above are the adoption of the NCO method for calculating customer marginal costs and the exclusion of the replacement cost adder for each functional category. This compromise is more than fair to noncore interests considering that we have already adopted the NCO method for every utility except SoCalGas and have also adopted the replacement cost adder for PG&E. Furthermore, in SoCalGas' last BCAP we acknowledged that the replacement cost adder was conceptually sound even though it wasn't adopted because of the limitations contained in the Global Settlement. In short, if this issue is fully litigated there is a strong possibility that we would adopt both the NCO method and the replacement cost adder, consistent with the policy adopted for PG&E.

VII. Transmission

A. Transmission Marginal Costs

Most of the differences between ORA and SoCalGas with respect to transmission marginal costs are the result of different recommendations with respect to the appropriate level of investment to be included in the resource plan. This issue is addressed below in a separate subsection.

However, there is one issue with respect to the appropriate marginal demand measure (MDM) for transmission. The Commission adopted MDM for SoCalGas is cold year throughput. CIG/CMA proposes changing this MDM to a weighted average of three design criteria: extreme peak day, firm service day, and cold year. SoCalGas states that the company would not object to this new MDM because the three elements are the design criteria that SoCalGas uses in planning the transmission system.

ORA submits that there is an insufficient record for purposes of changing the methodology adopted in D.92-12-058. (Re Rate Design for Unbundling Gas Utility Services, 47 CPUC2d 438, 454.) ORA argues there is simply nothing in the record indicating the basis for these estimates other than that they were based on "informed judgement." An estimate based on informed judgement is an insufficient basis for changing a methodology which has been in place for several years. In any event, the initial MDMs were based upon a combination of the utility's system design requirement and equity considerations:

> The utilities have chosen to advocate certain MDMs because they represent a combination of the multiple types of peak demand that the utility systems are designed to serve. They also support less extreme demand measures in order to spread costs in a 'equitable' manner instead of following cost-causation principles in a strict manner. (Re Rate Design for Unbundling Gas Utility Services, D.92-12-058, 47 CPUC2d 438, 454.)

There is no showing that the equity considerations which led to the adoption of a flatter allocator in 1992 have changed. Consequently, the CIG/CMA proposal is rejected.

B. Resource Plan

The Commission's adopted LRMC methodology requires that transmission marginal costs be based upon a resource plan which looks at the amount of investment required over a 15-year planning horizon to serve incremental demand while maintaining system reliability. The foundation for the resource plan is a fifteen year forecast of demand. SoCalGas relies, as it has in the past, on the most recent forecast of long term demand as set forth in the California Gas Report (CGR).

Since adoption of the LRMC methodology, a trend has emerged in which the transmission resource plan appears to have become a device for shifting costs from the noncore to the core. Decreasing forecasts of load growth over the 15-year planning horizon have led to decreasing investment levels. The lower investment levels lead to lower utility estimates of marginal transmission costs. This results in both lower marginal cost revenues and a greater portion of the revenue requirement being allocated by EPMC. EPMC effectively allocates 90% of the difference between the marginal cost revenues and the revenue requirement to core customers.

The trend of ever decreasing resource plan investments is set forth in the following table. The table begins with the 1993 transmission resource plan of $157 million and shows how it evolved into the current $18 million resource plan. It indicates both projects completed between BCAPs and projects that were dropped because of lower demand forecasts.

TABLE 4

Comparison of SoCalGas Transmission Resource Plans

	($Million)
Adopted 1993 BCAP	$157.0
Unneeded Projects	$55.9
Completed Projects	$12.6
Adopted 1996 BCAP	$88.5
Completed Projects	$15.3
Unneeded Supply Project	$28.0
Unneeded Capacity Projects	$26.5
Cost Estimate Adjustment	$0.8
Proposed 1999 BCAP	$18.0

The table indicates that, over a six-year period, the fifteen year resource plan has decreased from $157 million in 1993 to $88.5 million in 1996 and to $18 million in this proceeding. This reduced level of investment results in a significant reduction in transmission marginal costs from $0.09175/Dth ($1996) to $0.06154/Dth ($1999). The cost allocation impact of this reduction in transmission marginal costs is a shift of $28 million from the noncore to the core.

ORA submits that the company has failed to meet its burden of justifying such a significant reduction in transmission marginal costs and the corresponding shift in costs from the noncore to the core. ORA recommends that the Commission retain the resource plan adopted in the last BCAP adjusted downward to reflect projects that have been completed. This results in a resource plan of $77.3 million, a reduction of 13% from the resource plan adopted in the last BCAP.

SoCalGas' contention that it will only have to invest $18 million in transmission plant over the next 15 years is simply not credible in light of past investments, in ORA's opinion. In the 12-year period from 1986-1997, SoCalGas invested $194 million in resource plan type capital projects, an average expenditure of over $16 million per year. Now it would have the Commission believe that it will only spend $18 million over an entire 15-year period.

Except for projects that have been completed since the last BCAP, the entire reduction in the level of investments is premised on a long-term demand forecast which shows a lower rate of growth. SoCalGas does not adequately explain the reasons for the lower forecasted level of demand growth, nor does it explain the reasons for reduced demand forecast. It simply notes that the forecast for 2013 is 105 BCF lower that the forecast upon which the 1996 resource plan was based. Given the reservations expressed by the Commission in the last BCAP over long-term demand forecasts, ORA submits that the company has failed to meet its burden in justifying a $28 million shift in costs that results from a resource plan premised on an unsupported long-term demand forecast.

Rather than justifying its long-term demand forecast, ORA says the company simply takes the lower level of demand growth as a given and then claims that the current level of excess capacity, 25% under cold year conditions and 32% under average year conditions, is sufficient to get it through the next 15 years with only $18 million in resource plan investments.

In any event, the mere existence of excess capacity does not justify such a significant reduction in the resource plan. Excess capacity became a reality upon the completion of the Kern/Mojave project in 1992 and the PG&E Expansion in 1993. Notwithstanding this excess capacity, the company continued to invest in resource plan type projects spending approximately $42 million over just a four-year period from 1994 through 1997. The contention that SoCalGas, the largest gas local distribution company in the United States, will only have to spend $18 million over the next fifteen years is not credible given recent past investments during a period of significant excess capacity.

ORA views the most troubling aspect of the current resource plan to be the absence of the Adelanto project. In the last BCAP, SoCalGas proposed this $28 million project notwithstanding that system capacity exceeded forecasted level of cold year demand. While the project provided some peak day reliability, its primary justification was in providing customers additional flexibility through access to cheaper incremental gas supplies from Canada and the Rocky Mountains. SoCalGas agrees that this is still the ideal location for accepting incremental gas supplies but only if customers are willing to commit to the capacity.

ORA contends that removal of the Adelanto project from the resource plan is unreasonable even if one accepts the accuracy of the revised demand forecast in the 1998 CGR. There is already high level of usage at Wheeler Ridge. This high level of usage has led to forced reductions in nominations. This in turn has limited customer access to supplies from Canada and the Rocky Mountains. The Commission, in supporting the addition to new interstate capacity to California, believed that all customers would benefit from the gas-on-gas competition that would result from excess capacity. ORA argues that the very existence of Wheeler Ridge constraints in the absence of the Adelanto project is evidence that the 300 MMcf/d of incremental capacity provided by the project is still needed.

SoCalGas argues that its transmission resource plan looks at the capacity required on an annual basis first. It says there is over 30% of excess capacity leading into Southern California right now which is more than enough capacity to serve the demands of the customers. The system on an extreme peak day and a firm service day has the pipeline capacity to redeliver gas to customers. There is enough capacity to serve the customer's demands. Overall, incremental capacity is not needed to meet the forecasted system requirements over the next 15 years except for the system constraint in the Moreno station to Rainbow station segment of the SoCalGas system (Line 6900). A capacity expansion of approximately 17 miles of 30-inch pipeline is required to prevent curtailments of firm customers. The estimated cost for this expansion is $18 million.

SoCalGas compared this cost of $18 million over the next 15 years to the SoCalGas transmission resource plan approved in the 1996 BCAP. There were four projects in the 1996 BCAP transmission resource plan which have not been built, and are no longer necessary to meet the updated demand forecast.

C. Line 6900

The only capital investments included in the SoCalGas resource plan are the Phase 3 and 4 expansions of Line 6900 at an estimated cost of $18 million. No party challenges the need for these facility additions. However, several parties claim that the project is driven by demand growth on the SDG&E system and recommend that the costs be removed from the transmission plan and reassigned. SCGC recommends including the costs in SDG&E's resource plan. CIG/CMA recommends assigning 91% of the marginal costs to SDG&E and customers in Mexico and 9% to SoCalGas. Long Beach recommends assigning all of the costs to SDG&E's international border (IB) tariff. ORA agrees with SoCalGas that these facilities should be included in its resource plan.

The history of this issue is set forth in great detail in recent decisions and the testimony of several parties. (See D.98-03-073, pp. 108-113.) Suffice it to say that, prior to the 1993 BCAP, Line 6900 was treated as an exclusive use facility of SDG&E and it was assigned 100% of the costs. In the 1993 BCAP, the Commission approved a joint recommendation of SoCalGas, SDG&E, and ORA which treated Line 6900 as a common use facility. The costs associated with future expansions of Line 6900 were included in SoCalGas' resource plan. (Re Southern California Gas Co., D.94-12-052, 58 CPUC2d 306, 349.) The costs of expanding Line 6900 were also included in SoCalGas' resource plan approved in the 1996 BCAP although we expressed concerns about whether it was appropriate to include these costs in SoCalGas' resource plan as opposed to SDG&E's. Based on the record in this proceeding, ORA is of the view that the costs are appropriately a part of the SoCalGas resource plan.

SoCalGas asserts that Line 6900 is part of an integrated pipeline network designed to meet the growing retail and wholesale demands in southern Riverside and San Diego counties. The proposed expansion of Line 6900 is designed to serve approximately 100,000 new SoCalGas customers as well as additional wholesale demand from SDG&E, including service to Rosarito. Since these facilities are designed to meet load growth on both the SoCalGas and SDG&E systems, they are appropriately treated as common facilities and should be included in the SoCalGas resource plan.

SCGC (as well as Long Beach and CIG/CMA) opposes the inclusion of Line 6900 in SoCalGas' resource plan. It argues that notwithstanding SoCalGas' claims to the contrary, the record reveals that Line 6900 expansion is driven by growth in SDG&E's noncore load, especially new EG customers located near the California-Mexico border. Moreover, the primary beneficiaries of SoCalGas' proposed treatment of Line 6900 are SDG&E and its customers, while SoCalGas' wholesale and retail noncore customers, especially EG customers, stand to suffer significant harm. Accordingly, SCGC urges the Commission to reject SoCalGas' proposal and include Line 6900 in SDG&E's resource plan.

D. Impact of the Joint Recommendation

The JR would resolve the transmission resource plan and marginal cost issues through adoption of a compromise. The JR recommends a SoCalGas transmission resource plan of $32.5 million. The resource plan would include both the Line 6900 additions of $18 million and 50% of the costs (or $14.5 million) associated with Adelanto project. The Adelanto project was included in the 1996 resource plan and dropped from the current one. This facility addition would provide incremental access to Canadian and Rocky Mountain supplies. The 50% allocation is based upon the assumption that there is a 50% probability that the facility would be required at some point over the 15 year planning horizon. This assumption is clearly reasonable given the current problems associated with Wheeler Ridge constraints which can only worsen over the planning horizon in the absence of this project.

There is always uncertainty in any planning process. Predictions are a function of probabilities. Given this inherent uncertainty, basing the resource plan on a 50% probability that Adelanto will be needed is reasonable. Adoption of the JR would result in a transmission marginal cost of $0.0653/Dth. It is somewhat higher than the $0.06154/Dth marginal cost proposed by SoCalGas and lower than the ORA marginal cost of $0.1242/Dth. It is also lower then the TURN estimate of $0.08963/Dth. The net result is a 30% reduction in the transmission marginal cost adopted in the last BCAP.

VIII. Electric Generation

A. Single EG Rate for Both Utilities

Electric generators that require gas transportation over the systems of two utilities operate today under a regulatory structure that causes a mismatch between the pricing of gas and electricity. For gas transportation, the rates of each transporting utility are cumulated -- or "pancaked" -- so that the ultimate gas transportation rate the customer sees increases with the number of utilities involved in the transport. In this proceeding, SDG&E and SoCalGas propose to layer SDG&E's transportation rates on top of SoCalGas' wholesale rates to develop the transportation rates paid by EG customers in SDG&E's territory. The price the Power Exchange (PX) sets for purchases of electricity, by contrast, is uniform throughout the state (or within a zone if congestion occurs) -- a "postage stamp" rate that does not vary with distance or the number of utilities involved in the transmission from generator to customer.

The consequence of this pricing discrepancy is that some California generators pay much higher rates for gas transmission service than others, solely due to their location and the mismatch in regulatory pricing regimes, while all California generators receive the same price for sales made through the PX (in the absence of congestion). In the context of this case, generators in SDG&E's service area currently pay much higher gas transportation rates than those in the territory of SoCalGas, but they receive exactly the same price for their sales into the PX. This imposition of higher costs on San Diego-area generators means that less efficient generators in SoCalGas' territory will be more likely to make winning bids to the PX and be selected to dispatch and sell their electricity than will more efficient counterparts located across the border between these two companies. EGA says competition should be based on the efficiency of generating units and the shrewdness of their owners in the gas procurement and financial markets, not on the happenstance of which Sempra affiliate provides local gas service. It urges the Commission to overcome what it perceives as the anticompetitive distortions created by the current regulatory pricing arrangements by adopting a single EG gas transportation rate for SoCalGas and SDG&E.

The current pricing structure charges SDG&E electric generators an average of 11.5% more than electric generators located in SoCal's service area, thereby discouraging the operation of existing generators and the location of new generators in San Diego. Since all entities in California sell into the same PX and Independent System Operator (ISO) market, this 11.5% higher cost to SDG&E generators means that the SDG&E units are disadvantaged. EGA maintains that the discrepancies between the pricing of gas and electricity have harmful effects on consumers and on competition. The pricing mismatch favors inefficient generators in SoCalGas' territory over more efficient generators in SDG&E's territory. EGA contends that this mismatch gives new generators the wrong incentives for locating their generating facilities. New generators are encouraged by this pricing structure to locate outside of SDG&E's territory, even though more generation closer to the San Diego load center would be extremely valuable in terms of relieving transmission congestion and promoting system reliability. As more generators avoid SDG&E's territory, pressure builds to construct additional transmission lines into San Diego, which, EGA argues, creates its own problems.

Without a Sempra-wide EG rate, EGA believes the only option to building new transmission lines into SDG&E's territory is to increase reliance on reliability must-run (RMR) contracts between the ISO and individual generation units. These contracts allow the ISO to call on RMR units to operate on demand in order to relieve congestion and other problems on the transmission grid. But reliance on RMR contracts is expensive. They are cost-based contracts, and they tend to increase electricity prices over the prevailing prices in the PX. In EGA's opinion, reliance on RMR contracts inhibits the ability of the competitive market to develop.

EGA argues that the single rate proposal provides a simple and elegant solution to these problems. The single rate proposal promotes the proper incentives to attract generation to SDG&E's territory and to allow existing generators to take full advantage of their operating efficiencies when they compete in the market. Most important, the single rate proposal promotes competition and allows for development of creative and inexpensive market-based solutions to problems. TURN and UCAN support the single rate proposal. They assert that the single rate will produce benefits in the form of lower PX prices in some hours, less reliance on RMR units, and lower costs for RMR units when they are called on.

ORA, in opposition, responds that none of the arguments advanced by proponents of a single EG rate for both utilities justifies a departure from cost-based rates for gas transportation services. The fundamental problem with the single rate proposal, in ORA's opinion, is that it would reverse over a decade of progress in the effort to develop cost-based transportation rates for each of the state's gas utilities. Should SDG&E's EGs receive a lower rate, some other class of customers will have to pay more. Under the various proposals, this would either be the EGs in SoCalGas' territory or some other customer class. The proponents of the single rate have failed to justify the cross-subsidy inherent in the proposal.

ORA says that merely because EGs in SDG&E's territory pay a higher gas transportation than EGs in SoCalGas' territory is not justification for a subsidy. The new owners of SDG&E's gas fired power plants were aware of the transportation pricing differences at the time they elected to bid on the plants and were apparently of the view this was no obstacle to the profitable operation of the facilities. ORA maintains that the Commission should not try to improve their competitive position in the marketplace through an after-the fact change in the rules.

ORA disputes that a single rate would benefit ratepayers by lowering PX prices. It points out that the studies that show a strong correlation between gas prices and PX energy prices were completed before the start of the deregulated electric market; current data fail to support the correlation. The argument that a continuation of the pancaked rate structure will discourage the construction of new generation facilities in SDG&E's territory and increased reliance on expensive RMR contracts or the construction of expensive electric transmission facilities is similarly unpersuasive, in ORA's view. ORA refers to the presence of USGen as a viable option for new generation in SDG&E's territory as evidence refuting the contention that pancaked rates are discouraging new generation. This project was conceived well before there were proposals for a single EG rate across the two utilities.

We find that the public interest requires a single EG rate for both utilities. The argument and analysis presented by EGA, TURN, and UCAN are persuasive; ORA's objections have been overtaken by time.

ORA's argument that a single EG rate is a departure from cost-based rates is misleading. The costs ORA refers to are not expenses of the utility which can be confirmed by audit, but estimates of long run marginal costs increased by a "scaler" to reach the revenue requirement of the utility. The evidence presented in this case showed disputes over all estimates of marginal costs, disputes over the categorization of costs, disputes over the allocation of costs, and, most certainly, disputes over the scaler. Not only are ORA's "cost-based" rates more accurately "estimated cost-based rates plus scaler," but also each party who estimated costs managed to find that its costs were too high and others' too low. We must decide based on the evidence of record, but we have no illusions regarding the firmness of the costs we deal with. Nevertheless, with a Sempra-wide EG rate, the Sempra-wide costs (as accurately as we can predict) will be recovered.

ORA's second objection goes to the heart of the matter. A Sempra-wide EG rate will cause SoCalGas' EG customers to pay more and SDG&E's EG customers to pay less.[5] This is the type of cross-subsidy that long run marginal cost ratemaking was supposed to eliminate. And more to the point, one utility is not supposed to subsidize another utility. It is here where time and events have overtaken prior regulatory practices.

Changes in the energy industry are compelling this Commission to rethink its approach to regulation. Recent developments in the natural gas and electric industries have been dramatic: the restructuring of the electric utility industry, the rapid growth of competition in electric generation, competitive gas pipelines in California, the divestiture of electric utilities' generation plants, federal initiatives to promote competition in electric generation and gas transportation, the creation of the Power Exchange and Independent System Operator, and most important, the much-anticipated convergence between the natural gas and electricity industries. The growth of an increasingly competitive energy industry has exacerbated the tension between market-based pricing

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[5] The adjustment for the BCAP period is $8.976 million per year. (Appendix E, Table 3.) The accounting for the adjustment shall be the subject of an advice letter to be jointly filed by SoCalGas and SDG&E.

prevalent in competitive markets and cost-based pricing characteristic of traditional rate regulation. The single rate proposal is a feasible and realistic response to one of the tensions created by changes in and convergence of the energy industries — the mismatch between the pricing of gas transportation service and the pricing of sales and transmission of electricity in the competitive market.

Generators in SoCalGas' territory will not suffer a rate increase because of this shift. Appendix D, Table 8 shows that SoCalGas EG rates in effect as of January 1, 2000, are reduced by $20 million annually after the Sempra-wide rate becomes effective.

We are concerned that higher rates for EG service in SDG&E's territory than in SoCalGas' territory (estimated at over 11%) create a disincentive to build new generation in SDG&E's territory. Without new generation, future electric load growth will be served by additional electric transmission and RMR units, at increased costs. That increase will be paid by SDG&E's electric customers, primarily residential. A Sempra-wide gas rate reduces gas costs for SDG&E's customers and also reduces electric costs for SDG&E's customers. Further, the Sempra-wide rate increases competition between generators at the PX which is expected to reduce electric rates for all Californians. As a by-product of increased generation in SDG&E's territory some experts predict an improvement in air emissions as more efficient combined-cycle generators reduce the need for current, less efficient, generators.

We recognize that our decision on this issue is a departure from conventional regulatory theory. But we cannot ignore the vast changes energy restructuring has engendered, nor can we ignore the merger of SoCalGas and SDG&E and its implication of joint activity. We deliberately do not single out any one indicator, or group of indicia, upon which we base our result. Rather, we find that the public interest, as exemplified by all of the factors discussed, requires a single Sempra-wide EG rate.

B. EG Rate Segmentation

SoCalGas supports implementation of a segmentation process that would require a one-step analysis and be easy for its customers to comprehend. It proposes segmenting the EG rate based only on the throughput level of each EG customer. One rate would apply to EG customers whose annual throughput is less than three million therms. This rate would include both a volumetric transmission charge and a nominal customer charge. A second rate would apply to all EG customers whose annual throughput is greater than three million therms. This would be an all-volumetric rate applicable to 100% of the customer's throughput.

ORA supports the SoCalGas proposal. SCGC supports segmentation but proposes that it occur on the basis of level of service: distribution versus transmission.

SCGC recommends that the EG class be segmented to reflect the higher costs that distribution-level EG customers place on the system compared to transmission-level customers and that EG customers served through the high pressure distribution (HPD) system that consume more than three million therms per year be billed at the transmission level rate. SCGC argues that throughput is not a significant factor in the cost of service compared to the level of service, and there is very little difference in serving a three million therm load than a six million therm load. There is, however, a significant difference in the cost of delivering those therms through SoCalGas' transmission system, rather than through its more expensive distribution system. SCGC believes throughput is a fundamentally arbitrary basis for segmenting rates. If EG rates are segmented at three million therms without a cost basis, the precedent will be established for further segmentation based solely on throughput.

The major parties support segmenting the EG rate. SCGC qualifies its argument by agreeing that distribution level customers consuming over 3 million therms per year should be billed at the transmission level rate. Implementation of the SCGC proposal would require a two-step analysis: (1) does that customer use distribution or transmission level service? and (2) if the customer uses distribution service, does the customer consume over 3 million therms per year? SoCalGas supports implementation of a segmentation process that would require a one-step analysis and be easy for its customers to comprehend. SoCalGas proposes segmenting the EG rate based only on the throughput level of each EG customer. We agree with SoCalGas. Segmenting the EG rate based upon customers throughput maintains a ratemaking format easily understood by customers while also adhering to the cost-based ratemaking principles of the Commission. The adopted segmentation is equally applicable to SDG&E's EG class.[6]

A segmented transportation rate clearly complies with the cogeneration parity requirements of Pub. Util. Code § 454.4:

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[6] We are concerned about the impact of segmentation on customers using less than 3,000,000 therms per year. Especially on the SoCalGas system (and perhaps on the SDG&E system), those customers may experience a rate increase disproportionate to their consumption. Therefore we will order SoCalGas and SDG&E to jointly propose a Sempra-wide tariff for EG customers using 3,000,000 therms per year or less, as a class, which caps their rate at the level which prevailed at the EG rates in effect prior to the effective date of this order. Any shortfall in revenue shall be allocated to the >3,000,000 therm class. We recognize the complexity of such a proposal, and acknowledge that after analysis we might find it, or a modification, unreasonable.

> The Commission shall establish rates for gas which is utilized in cogeneration technology projects not higher than the rates established for gas utilized as a fuel by an electric plant in the generation of electricity, except that this rate shall apply only to that quantity of gas which an electrical corporation serving the area where a cogeneration technology project is located, or an equivalent area, would require in the generation of an equivalent amount of electricity based on the corporation's average annual incremental heat rate and reasonable transmission losses or that quantity of gas actually consumed by the cogeneration technology project in the sequential production of electricity and steam, heat, or useful work, whichever is the lower quantity.

Interpretation of this requirement has been controversial, and the controversy has only increased with the divestiture of SCE's and SDG&E's fossil-fired generating plants. The quantity of gas that the utility would consume to generate electricity -- the basis for the cogeneration parity that this statute is intended to guarantee -- loses all meaning when the utility no longer uses gas to generate electricity.

Section 454.4 may be outdated, and it may not be applicable, but it would not be improper to comply with its spirit. SDG&E initially proposed a rate design which it acknowledged did not meet the statute's requirements. Several parties presented proposals that split the EG class into segments. The answer to the question whether the segmented rate designs proposed in this proceeding comply with § 454.4's requirements appears to turn on fine points such as the number of segments and whether the segments are defined by usage or service level. Amidst all this, one clear point emerges: The adopted segmented rate proposal complies with § 454.4. Because it treats all electric generators alike, regardless of their size, location, or present or former ownership, the adopted segmented rate proposal grants parity to cogenerators, former utility electric generation plants, independent merchant plants, and any other gas-fired generator.

C. Anti-gaming Mechanism

SoCalGas supports elimination of the Cogenerator Gas Allowance (CGA) in conjunction with the adoption of anti-gaming measures aimed at insuring that the EG rate is limited to gas volumes that are used to generate electricity. The measures, which would be included as tariff conditions, would require separate metering where practical, for direct-fired electric generating facilities. Where metering is not practical, there would be a monthly volume limitation equal to the recorded power production in kWh multiplied by the average heat rate for the electric generation facilities. CCC/Watson supports the SoCalGas recommendations while SCGC opposes elimination of the CGA on the ground that it is required by Pub. Util. Code § 454.4.

ORA is uncertain whether the proposed tariff conditions are sufficient to prevent all gaming. ORA recommends a tariff condition requiring a meter on all electric generation facilities unless it can be demonstrated that it is not economically feasible or is otherwise impossible. This objective standard will help eliminate some of the uncertainty regarding SoCalGas' willingness to enforce a metering requirement.

In Resolution G-3242, provisionally approving an EG class advice letter, we found that the CGA can be eliminated without violating § 454.4 provided that it is accompanied by sufficient anti-gaming provisions aimed at limiting EG service to the amount of gas actually used in electric generation. Regardless of the anti-gaming provisions we adopt, we do not expect them to be totally successful. We expect some will try to beat the system. To minimize that happening, we adopt ORA's recommendation requiring a separate meter on all facilities used solely for the generation of electricity unless it can be demonstrated that it is not feasible. We would expect very few, if any, exceptions to this requirement.

D. Public Purpose Programs

CCC/Watson recommend that natural gas vehicle (NGV) program costs should not be paid by EG customers. They argue that since EG customers pay for the costs of low emission electric vehicles (EV) on the electric side, they should not have to also pay for NGV costs on the gas side.

ORA disagrees with the proposal and recommends that all customers continue to pay for NGV costs on an equal-cents-per-therm basis. The Commission, in considering low emission vehicle programs, has generally ruled that all customers in California benefit from having these programs. Because of this and the fact that no customer would volunteer to pay for these costs (similar to the Commission's policy on the allocation of transition costs), the Commission has ruled that all customers should pay NGV costs on an equal-cents-per-therm basis.

In D.95-11-035, the Low Emission Vehicle Investigation/Rulemaking (I.91-01-029, R.91-10-028), we continued our policy of allocating NGV costs on an equal-cents-per-therm basis: "Currently, the three natural gas utilities spread the cost of their natural gas vehicle programs on an equal-cents-per-therm basis over all volumes sold to all customer classes." (Re San Diego Gas & Electric Co., D.95-11-035, 62 CPUC2d 351, 449.) "We agree that the burden of these special programs should most accurately track the path of potential benefits and will require all three companies to continue allocating program costs on an equal-cents-per-therm basis." There is no reason to change this policy. All customers should continue to pay their fair share of NGV costs.

E. The CPUC Fee

CCC/Watson argues that SoCalGas' current method of collecting the CPUC fee from municipal utilities violates § 454.4 and should be modified. SoCalGas says this statement is inaccurate. Pub. Util. Code § 432(b) states:

> "The commission may establish different and distinct methods of assessing fees for each class of public utility, if the revenues collected are consistent with paragraph (2) of subdivision (a), except that the commission shall establish a uniform charge per kilowatt hour for sales in kilowatt hours for the class of electrical corporations and a uniform charge per therm for sales in therms for the class of gas corporations."

> Pub. Util. Code § 435 states, in pertinent part:

> "Sales in therms' means deliveries of gas in therms, without regard to ownership of the gas, subject to the jurisdiction of the commission, directly to customers and subscribers of each gas corporation, <u>except interdepartmental sales or transfers and sales to other privately owned or publicly owned public utilities furnishing electricity, gas or heat.</u>" (Emphasis added.)

Hence, it appears clear that the legislature intended to exempt the delivery of gas to certain recipients, like municipal utilities, from the CPUC fee addressed in Pub. Util. Code § 421.

We agree with SoCalGas.

IX. ITCS and Interstate Capacity

A. Summary

Three issues have been raised with respect to SoCalGas' long-term contracts for interstate pipeline capacity on El Paso and Transwestern: (1) the amount of interstate capacity which should be reserved for core customers and the estimated cost of that capacity; (2) the amount of interstate capacity that is expected to be stranded during the BCAP period and the allocation of those stranded costs to core and noncore customers through the ITCS account; and (3) the appropriate methodology for both allocating interstate pipeline refunds to customers and recovering Transwestern transition cost recovery (TCR) surcharges from customers.

ORA recommends maintaining the core reservation at its current level of 1044 MMcfd at an estimated cost ranging from $128 million in 2000 to $130 million in 2002. SoCalGas recommends increasing the reservation to 1076 MMcfd at an estimated cost ranging from $136 million in 2000 to $132 million in 2002.

ORA also recommends eliminating the core's responsibility for ITCS costs. ORA agrees with the company's estimated market value of the interstate capacity which will be made available for brokering. However, ORA's estimate for stranded capacity (ITCS) costs is slightly higher than the company's because of ORA's lower core reservation.

ORA further recommends that Transwestern TCR surcharges be recovered from all customers on an equal-cents-per-therm basis. Finally, ORA recommends that the $11.7 million in refunds SoCalGas has received from the interstate pipeline be returned to customers in the same manner in which they were initially recovered.

B. Core Capacity Reservation Costs

ORA recommends that the core reservation be maintained at its current level of 1,044 MMcfd with 744 MMcfd reserved on El Paso and 300 MMcfd on Transwestern. SoCalGas recommends increasing the reservation to 1076 MMcfd based upon the company's forecast of cold year demand for 2002, the last year of the BCAP period. The cost difference between these two estimates is approximately $4 million per year in reservation charges. Adoption of the SoCalGas proposal would reduce ITCS costs by shifting an additional $4 million in cost responsibility to the core. The ORA proposal has no cost allocation impact since it simply maintains the status quo.

SoCalGas notes that the core reservation was initially based upon a forecast of the core's cold year requirements. ORA's proposal ignores the core's cold year requirements and is instead based upon a goal of avoiding additional cost shifts.

ORA points out that the existing reservation is sufficient to meet the core's average year requirements; the 1044 MMcfd reservation level is significantly above average year requirements for each year of the BCAP. Because the cold year forecast upon which SoCalGas' reservation is based is an event which is expected to occur only once every 35 years, given the current excess of interstate capacity into the California market, there is simply no need for the core to continue reserving capacity that it is unlikely to need or use during the BCAP period. To the extent that the core's requirements are in excess of the reservation, it can simply purchase supplies at the border. Indeed, the Commission's recent decisions approving the GCIM authorize SoCalGas to purchase up to 10% of its demand on an annual basis at the California border without being subject to a reasonableness review. (D.97-06-061, p. 9, Conclusion of Law No. 10.)

ORA says that maintaining the reservation at its current level is also appropriate given the likelihood that core capacity costs will be unbundled at some point during the next three years. When this occurs, as it already has on the PG&E and SDG&E systems, core aggregators will no longer be required to take a pro rata share of the core reservation and can instead serve core customers with capacity obtained on the open market. This, in turn, will lower the amount of capacity that the core needs to reserve.[7] Increasing the reservation above the current level makes little sense given that the current reservation is likely to be in excess of the core's cold year requirements once core capacity costs are unbundled.

Finally, ORA argues, maintaining the current reservation and allowing the core to meet its cold year requirements through purchases at the border gives at least some recognition to the current inequities in the way interstate capacity costs are recovered. The core pays the full as-billed rate for the capacity reserved on its behalf. This is significantly greater than the market value of the capacity. Noncore customers, on the other hand, have been able to purchase capacity at market prices since the inception of the capacity brokering program. During the early years of capacity brokering, noncore customers were also responsible for a significant amount of stranded capacity costs. However, with SoCalGas' recent step-downs in its capacity holdings on Transwestern and El Paso, the amount of stranded costs have decreased significantly. Maintaining the reservation at its current level will at least give the core some limited opportunity to purchase capacity at a market price and ameliorates this inequity. For all of the above reasons, ORA contends the core reservation should be maintained at its current level of 1044 MMcfd.

SCGC supports SoCalGas. Out of concern for the core SCGC argues that it would be bad policy to bar SoCalGas from reserving adequate levels of capacity to meet projected core demand. It says the Commission must require the core to maintain sufficient capacity to meet its own needs, even under peak-year conditions. Any customer, including the core, must base its capacity

[7] Core aggregation currently accounts for about 5% of the core load.

reservations on its real need for firm capacity on an ongoing basis. SCGC, believing there is demonstrated need to increase the core's interstate capacity reservation, urges the Commission to approve SoCalGas' recommended core reservation of 1,076 MMcfd.[8] The JR adopts ORA's recommended 1044 MMcfd and associated costs.

C. Allocation of ITCS

Since the inception of the capacity brokering program, the core has been responsible for paying the full as-billed rate for interstate capacity reserved on its behalf while the noncore has been free to obtain capacity at the substantially lower market price. In addition to paying more for capacity, the core has also been responsible for a portion of the stranded costs that arise from the fact that the market value of the interstate capacity SoCalGas holds is significantly less than the rate it must pay El Paso and Transwestern under its long-term contracts. The stranded costs, which are the difference between the company's contractual obligations and the revenue obtained through brokering, are recorded in the ITCS account. Until now, the core and noncore have been allocated ITCS cost on an equal-cents-per-therm basis with the core's responsibility capped at a dollar value equal to 10% of the cost of the capacity reserved on its behalf. ORA recommends that the Commission eliminate the core's continuing responsibility for ITCS costs. Adoption of this recommendation would shift approximately $9 million in cost responsibility from the core to the noncore.

[8] SCGC's concern for the core has caused its position on every disputed issue to be to increase the costs the core must pay.

ORA cites numerous factors justifying the elimination of the core's responsibility for ITCS costs. First, the core has paid a disproportionate share of SoCalGas' contractual obligations for interstate capacity since the inception of the capacity brokering program. Not only does the core pay an above market rate for the capacity reserved on its behalf, it is also obligated to pay for a portion of the stranded costs associated with capacity that is marketed to the noncore through the capacity brokering program. This allocation was based on the premise that, since all customer classes benefited from slack capacity, all customer classes should share in the stranded costs. (D.92-07-025, 45 CPUC2d 47, 61.) ORA observes that at that time the core was already paying full value for a significant amount of slack capacity, because the core reservation is based upon a cold year requirement which is expected to occur only once every 35 years. This reservation amount exceeds the core's average year requirements by approximately 10%. ORA says that requiring the core to pay significantly above market value for considerably more capacity than can reasonably be expected to be used in a given year and then piling on an additional slack capacity component is simply adding insult to injury.

If this practice was ever fair, ORA believes the time to eliminate it has now arrived. In 1996, SoCalGas reduced its capacity holdings on El Paso and Transwestern by a total of 750 MMcfd. These stepdowns have significantly reduced both the amount of capacity that must be brokered by SoCalGas and the associated stranded costs. Given the magnitude of the benefits to the noncore arising from the elimination of a large portion of SoCalGas' contractual obligations for interstate capacity, ORA believes it is only fair that the noncore finally assume full responsibility for the remaining stranded capacity costs.

SoCalGas and the noncore parties argue that the Commission has considered and rejected ORA's proposal to eliminate the core's allocation of ITCS costs in prior proceedings. (e.g., D.97-04-082 at 69-70.) They contend ORA has not provided new arguments or new evidence in support of its proposal. SoCalGas says the established record on this issue demonstrates convincingly that both core and noncore customers have benefited from lower commodity costs as a result of excess interstate pipeline capacity. The core has paid a small portion of the ITCS contemplated in the capacity brokering implementation decision and should continue to pay a portion of the ITCS costs, subject to the 10% cap, in recognition of the benefit it receives.

This issue is unique to this company. It is not a generic issue appropriate for a statewide proceeding because with the relinquishment of its El Paso capacity, PG&E no longer has any stranded capacity costs to recover on a going forward basis through the ITCS account. Furthermore, the Gas Accord eliminated the core's responsibility for any remaining ITCS costs on the PG&E system.

The JR has resolved this issue by maintaining the status quo.

D. Forecast of ITCS Costs

In the last BCAP, the Commission elected to recover ITCS costs on a forecast basis rather than a recorded basis. In order to develop a forecast of stranded costs, the value of brokered capacity must first be determined. SoCalGas estimated the value at $0.12 per MMBtu based upon publicly available information regarding sales of El Paso capacity to third parties. The estimated value of $0.12 per MMBtu is approximately 34% of the as-billed rate. CCC/Watson recommends using an estimate of $0.24 per MMBtu based upon a simple average of 1998 monthly California border/San Juan basin differentials less fuel and commodity costs. ORA recommends using the company's more conservative estimate because it is more representative of the historical value of capacity. The higher estimate sponsored by CCC/Watson is based on one year of data which is not expected to continue after expiration of El Paso's short-term transportation contracts. The lower estimated value will help insure that ITCS costs are not undercollected. This in turn will insure that customers contemplating bypass at a future date will not be able to avoid these costs.

ORA used SoCalGas' estimated market value of capacity to develop a $26.5 million forecast for ITCS costs in 2000. This is slightly higher than SoCalGas' estimate of $24.5 million because ORA's lower core reservation makes more capacity available for brokering. This in turn, results in approximately $2 million in additional stranded costs.

E. Amortization of ITCS

The change from recovering ITCS costs on a recorded basis to recovery on a forecast basis has the consequence that the ITCS rate now includes two components: one for recovery of the previously recorded ITCS and another for recovery of future ITCS. The total ITCS rate for noncore industrial and commercial customers established by D.97-04-082 was $0.01160 per therm. On June 1, 1999, SoCalGas filed Advice Letter No. 2811 seeking to reduce the ITCS component of rates effective August 1, because the recorded portion of the ITCS account balance from the last BCAP will have been fully amortized as of that date. SDG&E filed Advice Letter 1157, July 2, 1999, to the same effect. ORA and TURN protested both advice letters and instead recommend that the ITCS component remain at its current level.

ORA says the problem with the proposed reduction in the ITCS rate is that it completely ignores the rehearing of D.97-04-082 on the allocation of interstate surcharges arising from the Federal Energy Regulatory Commission (FERC) approved settlements between El Paso and Transwestern and their customers. In D.97-04-082 the Commission allocated the surcharges to core customers. In D.98-07-100 the Commission granted rehearing after finding that it had erred in classifying these costs as something other than ITCS costs and in allocating them in a manner inconsistent with previous decisions. D.99-11-021 modified D.97-04-082, and reallocated $81.1 million of ITCS surcharges from the core to the noncore. The effect of this reallocation is discussed in Section XVI, infra. ORA's position on the proper level of the ITCS component of rates was formed prior to D.99-11-021. Because of overcollections in ITCS accounts and the reallocation of surcharges, we will reduce the ITCS component of rates, thereby lowering rates for all customers. (See Section XVI.)

F. Transwestern TCR Surcharges

The TCR surcharges represent Transwestern's recovery of take-or-pay, buyout, buydown, and contract reformation costs incurred through December 31, 1997. Prior to November, 1996 SoCalGas allocated these costs based on the core/noncore split of capacity rights on Transwestern. On November 1, 1996, SoCalGas reduced its capacity holdings on Transwestern from 750 MMcfd to 300 MMcfd. The remaining 300 MMcfd was assigned exclusively to the core. Since November, 1996, the company has been assigning the TCR surcharges exclusively to the core through the CFCA.

ORA argues that allocation of these costs exclusively to the core is inappropriate. These costs were incurred by Transwestern as a part of the restructuring of the gas industry at the federal level at a time when SoCalGas held capacity to meet the requirements of all of its customers, both core and noncore. ORA points out that the Commission has consistently held for over ten years that transition costs of this nature are the responsibility of all customers. As stated in D.87-12-039:

> These (transition) costs date from the era when the utilities bought gas and built their systems with the obligation to serve all types of customers. The purpose of identifying

> these costs now is to enable them to be shared equally among all current gas users. If the existence of these costs means that all customers cannot enter the newly competitive gas market with a "clean slate," at a minimum, out of a sense of fundamental fairness, we can ensure that everyone carries a slate that is equally dirty...
>
> We view take-or-pay, buy-out and buy-down costs related to pipeline purchases over the past few years as classic transition costs. (Re Rate Design for Unbundled Gas Utility Services, D.87-12-039, 26 CPUC2d 213, 229.)

ORA says that the issue is not whether SoCalGas currently holds Transwestern capacity on behalf of its noncore customers. The issue is the fair recovery of these transition costs from all gas users. Since noncore customers are still gas users they should be held responsible for their fair share of these costs. ORA recommends that these costs, estimated at $659,000 annually, be recovered, like other transitions costs, on an equal-cents- per-therm basis from all customers. ORA further recommends that the CFCA be credited in the amount of $1.849 million and that this amount also be allocated on an equal-cents-per-therm basis. This represents the amount allocated exclusively to core customers since November 1996.

G. Impact of the Joint Recommendation

The JR resolves issues relating to the core's reservation of interstate capacity, the core's responsibility for ITCS costs, and the allocation of Transwestern TCR surcharges. In each instance, the parties agree to maintain the status quo. This reflects ORA's position on the core reservation and SoCalGas' position on ITCS and the Transwestern TCR surcharge. ORA recommendations on the ITCS issue and the Transwestern TCR surcharge, if adopted, would shift approximately $ 10 million in annual costs from the core to the noncore. Since the JR simply maintains the status quo on each of the issues, there is no cost allocation impact.

The JR did not address the ITCS reallocation from core to noncore ordered by D.99-11-021. That reallocation is discussed in Section XVI, infra.

X. Wheeler Ridge

A. Roll-in Treatment

In D.95-04-078, the Commission elected to recover the costs associated with interconnecting SoCalGas' system with the Kern/Mojave pipeline and the PG&E Expansion (Line 401) on an incremental basis. (Re Southern California Gas Co., 59 CPUC2d 608.) These facilities provide customers with new access to approximately 650 MMcfd of Canadian and Rocky Mountain gas supplies. Under the incremental pricing approach, the $40 million investment in these facilities was recovered from the shippers that used the facilities rather than the general body of ratepayers. At the same time, the Commission also adopted a zone rate credit (ZRC) which effectively relieved shippers using the Wheeler Ridge facilities from any cost responsibility for the eastern portion of the SoCalGas system. The eastern portion of the system provides access to southwestern gas supplies over the El Paso and Transwestern pipelines.

In this proceeding, SoCalGas proposes to roll-in the cost of the Wheeler Ridge facilities into overall transportation rates. In conjunction with the roll-in, both the incremental pricing and the zone rate credit would be eliminated. Rolling the incremental facilities into rate base would increase the revenue requirement by $6.83 million. However, this would not result in a rate increase of that magnitude since the increase in the revenue requirement would be virtually offset by elimination of the zone rate credit. SoCalGas also proposes to terminate the long-term contracts for firm access to Wheeler Ridge currently held by SCE and SDG&E.

ORA was one of the original proponents of incremental pricing for the Wheeler Ridge facilities. However, ORA was never a supporter of the zone rate credit. In ORA's view, the incremental pricing for Wheeler Ridge facilities in combination with the zone rate credit, diluted the underlying purpose of incremental rate treatment. Since elimination of both incremental pricing and the zone rate credit is revenue neutral, ORA supports the proposal on the grounds that it would promote administrative simplicity. No party objects to rolled-in pricing for Wheeler Ridge, but there is some objection to relieving SDG&E and SCE from contracts regarding Wheeler Ridge, discussed below.

B. SDG&E and SCE Contracts

Although ORA supports the proposal to roll-in the remaining costs associated with the Wheeler Ridge facilities, it is concerned about the proposal to simply relieve SDG&E and SCE from their long-term contractual commitments to firm access at Wheeler Ridge. These contracts extend to 2006 and would result in demand charge payments to SoCalGas of approximately $6.8 million. SCGC recommends that SoCalGas be permitted to roll-in the Wheeler Ridge costs only on the condition that it continues to enforce its long-term contracts. It believes that relieving SDG&E, a SoCalGas affiliate, of its long-term commitment has the appearance of favoritism and undue preference; nor is it clear why SCE should be relieved from its obligations under its contract when it had to buy its way out of its long-term commitments to both gas supply in Canada and firm capacity on the PG&E Expansion project. (See D.97-12-040.) Given these factors, ORA tends to support the SCGC proposal. However, ORA is not sure that it can be implemented without SCE and SDG&E paying twice for the facilities; once through the contract and again through the rolled-in rate.

SoCalGas and SCE argue that SCE should not continue to be charged for access to the SoCalGas system at Wheeler Ridge while other shippers receive the same service as part of bundled intrastate transportation on SoCalGas. Those shippers, many of whom have firm upstream transportation service at Wheeler Ridge, would be receiving equivalent benefits to those received by SCE and SDG&E under their existing contracts. However, under the SCGC proposal, those shippers would be subsidized by the continued contractual payments made by SDG&E and SCE. SCE asserts that termination of the Wheeler Ridge access agreements will eliminate the present circumstance where customers with firm access rights are not receiving the full value of their Wheeler Ridge reservation charge. Specifically, customers such as SCE and SDG&E are not receiving the firm services they are paying for. SCE believes that this circumstance exists as a result of SoCalGas' windowing practices, whereby access to the SoCalGas system is based on how much gas SoCalGas determines can flow into each receipt point as opposed to the firm and as-available rights for access owned by shippers. SCE believes relieving it of its contract will have virtually no impact on overall transmission rates.

SDG&E points out that, unlike SCE which has ceased all use of its Wheeler Ridge access with the sale of its power plants, it continues to use Wheeler Ridge to interconnect with firm transportation on PG&E, PG&E-GT-NW, and TransCanada to provide a gas supply to its utility procurement customers. SDG&E expects to continue this use for the foreseeable future. Firm access to the SoCalGas system through Wheeler Ridge makes Canadian gas supplies available to SDG&E's utility gas customers on a firm basis. SDG&E supports a roll-in of the Wheeler Ridge facilities, but under a plan that allows SDG&E to retain firm access to the SoCalGas system as it is provided to shippers today. Having contracted for Wheeler Ridge access service through

October 2006 in order to ensure interconnection with the remainder of the firm contractual path to Canada, SDG&E declares that it should not now be expected to make a payment subsidizing other shippers in order to buy itself out of this right — a right it does not want to lose.

Further, SDG&E considers its Access Agreement with SoCalGas to have value to SDG&E and its utility gas customers. It argues although a buy-out payment has no rationale, a continuation of demand charge payments to SoCalGas would be appropriate and acceptable if it were treated as consideration for the access rights SDG&E currently receives. The Access Agreement, in this circumstance, should continue in effect.

Access protocols at Wheeler Ridge and other SoCalGas receipt points are as yet undetermined. SDG&E wishes to retain the current benefits of having made a long-term commitment that could well continue to be beneficial. The evidence regarding the SoCalGas proposal concerning the SDG&E and SCE contracts is unconvincing. We see no need to condition our authorization of rolled-in costs of the Wheeler Ridge facilities into overall transportation rates upon termination, buy-out, or modification of SDG&E's and SCE's contracts. SDG&E desires to continue its contract; we have no evidence of a compelling reason why it shouldn't. SCE desires to terminate its contract; we have no evidence why that desire should affect our decision to roll-in costs. SoCalGas and SCE may rescind their contract, but only if there is consideration for any release of potential ratepayer benefits.

XI. Storage

A. Summary

In D.93-02-013 (48 CPUC2d 107), the Commission unbundled noncore storage services for SoCalGas. Under this new regime, storage capacity and the related costs are first allocated to core customers and load balancing services. The remaining storage capacity and related costs are then allocated to the unbundled noncore storage program.

The allocation of costs between the core, load balancing, and the unbundled storage program is based upon three factors: (1) the estimated marginal costs for inventory, injection, and withdrawal capacity; (2) the amount of storage capacity needed to meet the core's peak day requirements, and (3) the amount of storage needed to provide balancing services. As with the transmission function, the process begins with the development of a resource plan which estimates the amount of investment needed to meet growth over a 15-year planning horizon. The storage marginal cost for each function is determined by dividing the total investment by the growth in demand. Marginal cost revenues for the core and unbundled storage program are then determined by multiplying the marginal costs for each function by the amount of capacity allocated to the core and the unbundled storage program.

Only those noncore customers desiring storage services contribute to the recovery of the unbundled storage program's revenue requirement. The costs associated with any unsubscribed capacity is given transition cost treatment and is recovered from all customers through their transportation rate. (Re Natural Gas Procurement and Systems Reliability Issues, D.93-02-013, 48 CPUC2d 107, 130.) The differences between the company and ORA with respect to storage issues relate to the withdrawal reservation for the core, the estimated marginal costs for all three functions, and the continuation of balancing account protection for the unbundled storage program.

B. Storage Marginal Costs

The ORA and SoCalGas storage marginal cost estimates are set forth in the following table.

TABLE 5

Fixed Costs

	Injection $/Mcfd	Withdrawal $/Mcfd	Inventory $/Mcf
ORA 2000$	33.51	13.64	0.22
SoCalGas 1999$	19.81	11.65	0.21

Variable Costs

	Injection $/Dth	Withdrawal $/Dth
ORA 2000$	0.0128	0.0178
SoCalGas 1999$	0.0124	0.0173

ORA accepted the company's storage resource plan. Consequently, all of the differences in the marginal cost estimates are the result of methodological differences. ORA includes a replacement cost adder for each of the storage functions while SoCalGas does not. The appropriateness of including a replacement cost adder has already been addressed in an earlier section of this opinion. (Section VI C.)

C. Core Withdrawal Reservation

SoCalGas proposes no changes in the core reservations for inventory capacity (70 Bcf) and injection capacity (327 MMcf). However, it does propose an increase in the withdrawal capacity reservation from 1985 MMcfd to 2082 MMcfd. ORA recommends retaining the current reservation on the ground that there has been no cost-benefit analysis to justify the proposed increase in the reservation. TURN proposes decreasing the reservation to 1782 MMcfd. TURN's analysis takes issue with SoCalGas' estimate of the amount of flowing supply available on a peak day. It is also based upon a cost-benefit analysis indicating that the purchase of flowing supplies on a peak day is considerably more economical than the reservation of additional withdrawal capacity on a year round basis.

SoCalGas' basis for the proposed increase in the withdrawal reservation is the forecasted increase in the core's peak demand. The company increased the reservation level in proportion to the increase in peak demand. ORA asserts that the proposed increase is unaccompanied by any cost-benefit analysis. The company has failed to demonstrate that this approach to meeting growth in peak day demand is economical given the availability of flowing supplies. SoCalGas does not take issue with the ORA contention that flowing supplies could make up the difference on a peak day. Nor does SoCalGas demonstrate that an increase in the withdrawal reservation is the cheapest alternative. Under those circumstances, argues ORA, the proposed increase in the reservation should be rejected in favor of the status quo.

TURN was the only party to present a cost-benefit analysis on the most economical alternative for meeting the core's peak day requirements in an environment of significant excess interstate capacity. That analysis indicates that not only should the forecasted increase in the core's peak day demand be met through flowing supplies, the current reservation could actually be reduced by 200 MMcfd given SoCalGas' underestimation of the amount of flowing supplies available on a peak day. TURN's analysis of the economics of using flowing supplies versus storage withdrawal capacity assumed a cost of gas ten times higher than the current cost of gas. Even with this assumption, the analysis demonstrated significant savings to the core from using flowing supplies rather than storage withdrawals to meet the residual portion of peak day requirements. SoCalGas' rebuttal to TURN's analysis consisted of two sentences:

> Severe peak day events in Chicago gas markets (as well as here in the California electric PX market) indicate that the

> price of peak day supplies can exceed $20/mcf. TURN's recommended 1782 MMcfd storage withdrawal reservation must be rejected because their analysis is too casually based upon speculative gas cost figures that have no reliable historical basis. (SoCalGas, Watson, Ex. 71, pp. 3-4.)

ORA submits that TURN's analysis of the economics of using flowing supplies versus storage withdrawal capacity is much more convincing than SoCalGas' unsubstantiated assertions regarding the possibility of gas prices exceeding $20/mcf. ORA supports TURN's lower withdrawal reservation as an alternative to simply maintaining the status quo. ORA contends that SoCalGas' proposal does little more than reduce its potential risk in the increasingly competitive noncore storage market by assigning additional costs to captive customers.

D. Noncore Storage Balancing Account

SoCalGas is currently exposed to virtually no risk for the costs allocated to its storage operations. The storage costs allocated to the core market remain bundled in core rates and are subject to 100% balancing account protection through the CFCA. The costs allocated to load balancing services also remain bundled in rates and are allocated to core and noncore customers. The stranded costs associated with the unbundled storage program are treated as transition costs and given 100% balancing account protection through the NSBA.[9]

ORA recommends that the NSBA be eliminated and that SoCalGas be fully at risk for costs allocated to the unbundled storage program. At the same time, it should be granted increasing pricing flexibility with respect to its noncore

[9] The forecast for subscribed capacity under the unbundled storage program is subject to 75/25 balancing account protection. SoCalGas is 100% at risk for any incremental investments made to serve noncore demand for storage services.

storage services. ORA believes these steps are needed to level the playing field between the incumbent utility and independent storage providers such as Wild Goose and Lodi Gas Storage (Lodi).

SoCalGas proposes to retain the NSBA unless four conditions are met: (1) the core retains sufficient storage capacity to meet its reliability requirements; (2) regular daily balancing is instituted; (3) SoCalGas is given pricing flexibility similar to independent storage providers; and (4) the company is free to sell and manage its unbundled storage assets. It further recommends that that issue be addressed in the GIR proceeding rather than this BCAP.

Since 1992 the Commission has been concerned with the development of an independent competitive storage market in California. The Commission's first step in that direction was the unbundling of storage costs for both SoCalGas and PG&E so that noncore customers could choose their own storage service providers in the event independent storage services became available. The next step was the granting of a certificate of public convenience and necessity (CPC&N) to Wild Goose, the first independent storage provider to receive a certificate in California. The Commission is currently considering the request of Lodi for a CPC&N.

Given the emergence of competition in the storage market, ORA says the time has come to move the process a step further by leveling the playing field between SoCalGas and its potential competitors. Independent storage providers do not have balancing accounts to protect them from risk in the marketplace, nor are they limited in the prices they can recover from the marketplace. ORA believes it is unfair for SoCalGas to continue receiving balancing account protection for its unbundled storage costs when no similar protection is accorded new market entrants. As a further step in moving toward a competitive storage market, it recommends that NSBA protection be eliminated and the utility be granted pricing flexibility comparable to that available to independent storage providers.

This recommendation is identical to one ORA made in the SoCalGas PBR proceeding. SoCalGas opposed the PBR recommendation, arguing it was precluded by the Global Settlement. Since the Global Settlement has expired, it now argues that the issue should only be addressed in the GIR proceeding. This is not a generic issue. SDG&E has no storage facilities of its own and the Gas Accord resolved the issue for PG&E by placing shareholders fully at risk for its unbundled storage program. Since it is not a generic issue it is appropriately addressed in this BCAP.

E. Impact of the Joint Recommendation

The JR would resolve the issue of the core withdrawal reservation as well as the issues surrounding the unbundled storage program. The parties agree to a core withdrawal reservation of 1935 MMcfd. This is the midpoint between the TURN and SoCalGas recommendations. The parties also agree to limit the costs allocated to the unbundled storage program to $21 million and to provide 50/50 balancing account protection together with upward pricing flexibility capped at 120% of the current tariff rates. The $21 million is $11 million less than the fully scaled marginal cost revenues that would flow from the other elements of the joint recommendation. This $11 million shortfall would be allocated to NSBA and recovered from all customers on an equal-cents-per-therm basis.

The JR provides a reasonable resolution of the storage issues notwithstanding the complaints of WHP and SCGC. It represents a significant step toward leveling the playing field between SoCalGas and new market entrants. Although SoCalGas will not be fully at risk for its unbundled storage program, the 50/50 balancing account protection represents significant movement in that direction.

SCGC complains that the level of risk is really only 64/36 because the storage program is only allocated $21 million rather than the fully scaled amount of $31 million. Since SoCalGas is accepting a significantly greater level of risk for the unbundled program it is reasonable for the level of risk to be set close to the unscaled marginal costs. The $21 million figure accomplishes this. That amount is close to the embedded cost of the facilities and is actually greater than the unscaled marginal costs.

WHP avers that it is participating in this proceeding because the rates and terms for storage service by SoCalGas will directly impact WHP's ability to compete for customers in SoCalGas' service territory; its ability to compete will also depend on the implementation of the Commission's "let the market decide" policy to level the playing field for all storage providers as they compete for business. SoCalGas' testimony concerning the continuance of the NSBA and the conditions it would require to be met in order to agree to give up the subsidy provided by that account and become completely at risk for its noncore storage costs generated WHP's interest. WHP firmly believes that the legislative and Commission policy of advancing storage competition will never become a reality in California as long as monopoly storage providers are allowed to reach into captive ratepayers' pockets to make up for noncore storage revenue shortfalls.

In implementing its position WHP urges the Commission to:

1. Reject the "All Other Storage Issues" provisions of the JR.

2. Reject the transmission resource plan recommended in the JR as contrary to existing Commission LRMC methodology.

3. Eliminate the NSBA. This elimination of the NSBA can occur without considering SoCalGas' conditions to that elimination. However, should the Commission determine to address those conditions in this BCAP, WHP recommends:

   - Reject the SoCalGas condition that the core be allocated sufficient storage as unrelated to the issue of elimination of the NSBA.
   - Reject the SoCalGas condition that regular daily balancing be implemented as unnecessary to the elimination of the NSBA.
   - Allow SoCalGas sufficient pricing flexibility for its unbundled storage services and asset management flexibility, on the condition that SoCalGas' storage and transportation tariffs do not inhibit fair competition in SoCalGas' service territory.

4. Ensure that only storage costs are in storage rates, and that they are not included in transportation rates.

5. Ensure that the default rates of utility storage services, if continued to be priced with LRMC methodology, is not manipulated by SoCalGas' resource plans or other means that prohibits fair competition by other storage providers.

For the reasons discussed in other portions of this opinion we are adopting the JR. Our analysis of WHP's objections to the "All Other Storage Issues" leads to our conclusion that they are without merit. First, we do not "ensure" our findings on costs and allocations. Long run marginal costs are based upon estimates of costs, estimates of sales, and predictions of the future conduct of many parties. We hope we have reasonable estimates; we "ensure" nothing other than our belief that our decision is reasonable based on the evidence.

Second, WHP complains about the NSBA. The JR moves towards WHP's position. Presently the NSBA is a 100% balancing account assuring

SoCalGas' storage revenue. The JR moves to a 50/50 balancing account. Moving half way toward a party's position should not be disparaged.

The parties opposing the JR also argue that its treatment of the unbundled storage program either ties our hands or may be inconsistent with what we ultimately adopt in the GIR proceeding. Neither is the case. We are free to address whatever storage issues we deem appropriate in the upcoming cost/benefit phase of the GIR proceeding. The parties to the JR simply recommend that the changes not have any cost allocation implications prior to 2003. Furthermore, the JR expressly provides that storage issues may be reconsidered in the event that significant changes to storage operations or balancing rules are proposed in the GIR proceeding.

In summary, the storage provisions of the JR represent a reasonable interim step toward leveling the playing field between the utility and new market entrants. That step should be taken now since the timing of final Commission action in other proceedings is uncertain.

XII. Other Operating Costs

There is no dispute regarding SoCalGas' recommendations for unaccounted for gas, well incidents and surface leaks, carrying cost of gas in storage, and company use fuel. SoCalGas' forecast for unaccounted for gas is a factor of 1.27% of total annual throughput for the 1999 forecast period. Based upon five-year historical data, SoCalGas recommends that annual losses from surface leakage, well incidents, and field blow downs be estimated at 63 MMcf/d, less than half the estimate for the 1996 BCAP period. SoCalGas estimates the carrying cost of gas in storage to be $1,702,000 in BCAP year 2000; $1,710,000 in BCAP year 2001; and $1,710,000 in BCAP year 2002. Forecasted company use fuel includes usage at transmission compressor stations, storage fields, and miscellaneous company use. Transmission fuel is estimated at 3,865

MMcf per year, storage fuel is estimated at 2,600 MMcf per year, and miscellaneous company use is estimated at 355 MMcf per year. No party opposed these cost estimates and they will be adopted.

XIII. System "Window" Procedures

PG&E has raised the issue of SoCalGas' operation of its receipt point "windows." SoCalGas' windowing procedure is an allocation methodology that establishes the amount of throughput capacity available at each of its interstate gas transmission receipt points on a daily basis for customers trying to ship gas through those receipt points for volumes to be received into the SoCalGas intrastate transmission system. Arguing that it has problems with SoCalGas' current windowing process, PG&E recommends that SoCalGas should modify its windowing procedure to include: (1) a fixed minimum window to be established at each receipt point on SoCalGas' system; (2) a fixed minimum window at Wheeler Ridge for PG&E in the amount of 440 MMcf/d; (3) the establishment of Hector Road as a normal receipt point; and (4) SoCalGas' development of a system of access to its transmission system based on firm and as available contract rights.

SoCalGas responds that the issues PG&E raises concerning SoCalGas' "windowing" procedures are addressed thoroughly in Gas Industry Restructuring and therefore should not be addressed in this BCAP.

In D.99-07-015, we addressed SoCalGas' windowing procedure and requested that the utility file an advice letter containing proposed windowing tariffs. In response, SoCalGas filed A.L. 2837, protested by PG&E, which is currently pending. Additionally, in I.99-07-003 the windowing procedure is being considered. The issue is not new. It was considered in D.99-07-015, is being considered in regard to A.L. 2837, and will be considered in I.99-07-003. There is no need to consider it here.

XIV. Hub Services

SoCalGas' Hub services provide interruptible parking, loaning, and wheeling gas service. Currently, revenue from Hub services is credited to core customers through the GCIM. This treatment is based upon a finding by the Commission that the assets used to provide the services are funded by core customers. SCGC claims that SoCalGas has a conflict of interest in operating its Hub services and to remedy this conflict the Commission should remove Hub revenues from the GCIM and allocate them to all customers on an EPMC basis. Since Hub services rely on core assets, ORA continues to support the current mechanism. SCGC suggests a variety of changes to SoCalGas' operating procedures to circumscribe what it perceives to be SoCalGas' ability to use its control over monopoly services to promote its optional Hub and unbundled storage services. In addition, Edison argues that Hub revenues should be shared with noncore customers.[10]

All the foregoing issues are currently being reviewed in GIR. It is appropriate that they remain, and are decided in, that proceeding. D.99-07-015 states as part of GIR (I.99-07-003) the Commission will "examine the possibility of a conflict of interest between SoCalGas' hub services and core procurement in the cost/benefit phase of this proceeding" (D.99-07-015, *mimeo.*, at 48). This examination will include the possibility that "hub service revenues would be removed from the GCIM calculation." (Id., at 49.) Furthermore, many of the issues addressed involve operational matters and procedures clearly outside of

[10] Edison's proposal was made and rejected in SoCalGas' last BCAP. (D.97-04-082, at p. 82 in A.96-03-031.)

the parameters of a BCAP proceeding, the purpose of which is cost allocation and rate design.

XV. RLS Tariff

A. Arguments

SCGC, CCC/Watson, Kern River, Questar, and Edison recommend that the Commission order SoCalGas to eliminate the RLS tariff. The RLS tariff allows SoCalGas to impose a higher unit rate for transportation service to customers that partially bypass its system. Under the RLS tariff, SoCalGas may charge a rate for residual load service that is up to an amount equal to the product of the current tariff rate times the ratio of the customer's load factor before bypass to its load factor after bypass.[11] Thus, partial bypass customers face the prospect of paying an RLS rate that is so high as to make partial bypass uneconomic. The parties' experience is that the threat of incurring the higher RLS rate for residual service undermines the economic attractiveness of alternative pipelines, particularly for EG customers with multiple facilities.

The RLS tariff was implemented by the Commission in D.95-07-046 (60 CPUC2d 505) to close a regulatory gap which would unfairly reward noncore customers for partially bypassing SoCalGas. In this proceeding, the parties requesting termination of the RLS tariff are either competitors of SoCalGas seeking to gain a competitive advantage through regulation or customers that have considered in the past, or are actively considering, bypass projects. SoCalGas advocates that the RLS tariff should remain in full force and effect,

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[11] A customer's load factor is the ratio of its average daily demand to its peak daily demand. The customer's total annual volume divided by 365 measures its average daily demand. Peak daily usage is either measured or estimated depending upon the availability of data for the customer.

modified only in certain minor respects to account for changes created by electric industry restructuring.

SoCalGas observes that arguments against the RLS tariff in this BCAP are similar to arguments made and rejected in its 1996 BCAP, where the Commission considered arguments to terminate the RLS tariff by some of the same parties making the same arguments in this proceeding. The Commission concluded that the RLS tariff, as implemented in D.95-07-046 and amended slightly to incorporate certain SoCalGas-requested changes, should remain in effect. (D.97-04-082, at 134.) In so concluding, the Commission reviewed and rejected a variety of complaints. The Commission described the purpose and the general methodology of the RLS tariff:

> In D.95-07-046, the Commission approved a modified SoCalGas proposal to implement a load-specific flexible rate design for noncore customers who choose to partially bypass SoCalGas' transportation system. This design is known as the Residual Load Service (RLS) tariff.
>
> The RLS was implemented in order to close a regulatory gap which would have unfairly rewarded noncore customers for partially bypassing SoCalGas. This gap arises because SoCalGas, due to utility franchise rights, is required to serve all customer load within its service territory. Without the RLS, other gas transportation providers would have been able to contract with SoCalGas' noncore customers to provide their baseloads at lower, negotiated rates and leave SoCalGas obligated to serve those customers' high-cost peaking loads at tariffed rates. The losses resulting from this loss of noncore base load, combined with the requirement to serve high cost residual load at tariffed rates, would have been borne by SoCalGas' shareholders and remaining captive customers. The RLS was implemented to ensure that noncore customers' costs of partially bypassing SoCalGas internalize the externalities that their bypass places on the general body of ratepayers (D.95-07-046 slip op. at 15).

> Under the RLS, SoCalGas is allowed to negotiate rates for gas transportation with each noncore customer who decides to bypass. Rates must be negotiated between a floor equal to SoCalGas' short-run marginal cost and a default ceiling rate equal to the product of the current tariff and the ratio of the customer's load factor before bypass to the load factor after bypass. (Id. at 13.) The RLS does not apply to off-spec gas, refinery produced gas or gas produced and consumed within the service area of a wholesale consumer. (Id. at 17.) The RLS was approved for an interim period, until implementation of the instant BCAP. (D.97-04-082, at 127-128.)

SoCalGas says the foregoing discussion is as accurate now as it was in 1997. So too is the language from SoCalGas' 1996 BCAP decision where the Commission describes the necessity for the RLS tariff to remain in place.

> . . . in order to discourage bypass which would leave SoCalGas providing high-cost peak rate service at low tariffed rates to customers who partially bypass. Without the RLS tariff, SoCalGas' class average volumetric rate structure would provide "poor price signals to noncore customers and may promote uneconomic bypass by providing an under priced insurance policy to customers with market alternatives." (D.97-04-082, at 134.)

In making this determination, the Commission considered and rejected various arguments which have been repeated in this 1999 BCAP proceeding.

Kern River and Questar (the Pipelines) have brought the argument against the RLS tariff up-to-date. They assert that its function to discourage any attempt to partially bypass the SoCalGas system is anti-competitive with the result completely at odds with the Commission's commitment to fair competition in general and to competition among pipelines as announced in D.98-03-073, which approved the merger of the parent corporations of SoCalGas and SDG&E. The Pipelines note that the CEC has recommended eliminating the RLS tariff due to its anti-competitive effects.[12] They urge the Commission to join the CEC in recognizing the anti-competitive effects of the RLS tariff and to eliminate it immediately.

The Pipelines contend that when the Commission first adopted the tariff in D.95-07-046, it could not have possibly contemplated the impact the tariff would have on the emerging competitive market in electric generation. Nowhere in the Commission's Yellow Book or Blue Book, nor even in the Commission's Preferred Policy Decision,[13] is there a prediction that within two years of the issuance of the Policy Decision the basic elements of a more competitive electric generation market would be in place, complete with the sale of virtually 100% of the gas-fired generation of the three largest investor-owned electric utilities in California. Even more surprising is the explosion of interest in the construction of new electric generation plants, designed with efficient clean-burning combined-cycle turbine technology. But not surprising, the threat of the high RLS tariff rate is so ominous that the tariff has never been used, and SoCalGas has always succeeded in getting customers considering such bypass to remain full requirements customers.

The Pipelines say that the impact of the RLS tariff is not limited to economic theory. Their witnesses, representing competing pipelines seeking to enter the southern California market, uniformly reported that customers were unwilling to commit to their projects in a binding manner so long as the RLS

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[12] Comments of the California Energy Commission in Response to the Market Conditions Reports Filed in the Natural Gas Rulemaking, dated September 1, 1998, filed in R.98-01-011.

[13] D.95-12-063, as modified by D.96-01-009.

tariff was in effect. They say the anti-competitive effect of the RLS tariff is dramatically illustrated by the fact that the Questar Southern Trails project has firm commitments for capacity on its eastern segment, which delivers to the California border, but, as a result of the RLS tariff, no commitments on its western segment, which traverses southern California.

The Pipelines' witnesses testified that new generators, the ones that are locating along the Kern-Mojave corridor, are not exposed to RLS. They argue that when one set of electric generators has an RLS penalty and another set does not, it is an uneven playing field. SoCal's load will be bypassed not by gas pipeline, but by wire; which is the biggest flaw of residual load service. This phenomenon is dramatically reshaping the electric market in southern California, in the Pipelines' opinion. They said the developers of new EG merchant plants have intentionally located their plants away from the Los Angeles basin, the heart of the southern California electric load center, and have sited their facilities where they can either access FERC-regulated interstate pipelines, operate outside of the service territory of SoCalGas, or take advantage of the postage-stamp electric transmission rates in California to "bypass by wire" and transmit electricity generated outside of SoCalGas' territory to serve load which in the past was served by electric generation in the Los Angeles basin.

The Pipelines contend the effect of the RLS tariff is not merely to shift generation plants around California like pieces on a giant monopoly board. They point to the serious harm being done to investors in California's utility infrastructure, harm which they contend is unlawful because it is unduly discriminatory. They pose an example of a generator who operates a peaking power plant, and takes all of its gas demands from SoCalGas. This customer will impose a variable, low load factor demand on SoCalGas as it attempts to serve the fluctuating peaks in electric demand during a given day, month, or year.

This customer will pay only the tariffed transportation rate of SoCalGas. In contrast, if an existing generation customer of SoCalGas were to baseload a portion of its demand with an alternative pipeline and to continue to serve its peaking load from SoCalGas that customer would pay a substantial additional penalty on its transportation bills, even if its remaining demand on the SoCalGas system was identical in every way to that of the hypothetical peaking plant. Both customers would impose the same costs on the system to serve the same variable load. The Pipelines ask, is there any reason to place such disparate rate treatment on customers who impose identical demands on SoCalGas' system? They argue strongly that there is not, and that such a result would constitute unlawful discrimination in rates in contravention of Pub. Util. Code § 453.

The Pipelines believe that SoCalGas, by adhering to monopoly utility defensive tactics, and seeking to threaten customers into remaining on the system, is unwittingly encouraging even more bypass, discriminating against the existing generators in its service territory, severely eroding its own markets and revenues, and encouraging jobs and investment to flee southern California for the north or for out of state locations.

The Pipelines maintain that the RLS tariff is not cost based. Not only is the operation of the RLS tariff unrelated to cost incurrence, but in most cases it will impose greater costs on customers who impose lower transmission costs on the system. A customer who shifts from taking full requirements from SoCalGas to partial requirements — in other words, a customer who is the target of the RLS tariff — will in most cases reduce its cold year annual throughput, which is the basis for allocating transmission costs. But under the RLS tariff, that customer will be charged a higher rate, a multiplier of the otherwise applicable tariff rate, because its load factor will have declined after the change in service. So although this customer imposes lower transmission costs on the system, it will be required under the RLS tariff to pay higher rates. Thus, it is clear that the RLS tariff has no basis in cost causation. The RLS tariff punishes customers solely for the offense of having lower load factors, even though they are not imposing greater costs on the system. In short, in the opinion of the Pipelines, there is no rational economic basis for retaining the RLS tariff.

The Pipelines state that SoCalGas cannot substantiate its claim that bypass will always result in a reallocation of costs to other ratepayers — the Pipelines believe the zero sum game is dead. They claim that SoCalGas continually implies that other customers will suffer from any bypass, in the face of mounting evidence that this is not true. They believe elimination of the RLS tariff, with its anti-competitive effects, would encourage new pipelines to come into the basin and promote repowering of existing plants, to provide reliability and increase SoCalGas throughput. Most importantly, utility ratemaking in such a competitive environment is not a zero sum game. Witnesses have testified to the change in the "static, steady state environment" which existed prior to electric deregulation. The Pipelines conclude that SoCalGas is very likely losing load as a result of the RLS tariff and could actually gain revenue and throughput by getting rid of it, embracing bypass, and encouraging the repowering of plants within the Los Angeles basin.

SoCalGas and TURN strenuously object to abolishing the RLS tariff. They argue that the attempt is no more than a transparent exercise in profiting the interstate pipelines and shifting costs from large customers to captive customers. Their argument, succinctly stated, is: The RLS tariff only prevents uneconomic partial bypass; therefore it is not anti-competitive. The interstate pipelines could obviate the problem by increasing capacity to provide peaking service, but they don't because they cannot sell that capacity. The RLS tariff is market based because it competes with other pipelines; cost based tariffs are needed to protect ratepayers without competitive choices; where there is competition a market based tariff is reasonable. Eliminating the RLS tariff will shift fixed costs to full requirement ratepayers. Revenue allocation is based on forecast throughput. If more noncore customers (including EG and others) obtain base load gas from competitors, the noncore throughput will decline. Since the company's revenue requirement for fixed costs remains constant, the lost throughput will lead directly to higher core rates in the next BCAP. Because storage will provide peaking service without the need to oversize pipeline capacity, the pipelines should encourage new storage providers.

CCC/Watson argues that the RLS tariff is a tying arrangement in violation of antitrust laws. SoCalGas, to the contrary, asserts federal antitrust laws concerning tying arrangements do not apply to the regulated utility industry. As a state regulated entity, SoCalGas is immune from antitrust liability under the doctrine of state action. (Parker v. Brown, 317 U.S. 341, 63 S.Ct. 307 (1943).) Active regulation by the CPUC qualifies SoCalGas for this exemption.

B. Discussion

We are not persuaded that the RLS tariff should be abolished at this time. We have reviewed the discussion in D.95-07-046, D.97-04-082, and D.98-03-073 (the merger decision) regarding the RLS tariff and competition and find that the arguments in favor of retaining the tariff have weight, but that weight is rapidly being shed. We have set forth some of the arguments above and will not repeat them.

That significant changes have occurred in the electric industry since 1995 is obvious: the divestiture of generating facilities by the electric utilities, gas pipeline competition, the ISO for transportation of electricity, and the PX for pricing electricity. Competition between electric generators is here, and a substantial portion of that competition is between gas-fired generators. But we cannot fail to realize that the RLS tariff is ineluctably tied to the equation that throughput loss equals increased rates for the remaining SoCalGas customers. Contrary to the assertions of those who would do away with the RLS tariff, this is a zero sum game. The Pipelines say abolish the RLS tariff and "the rising tide of generation will lift all throughput" (R.B. 16). From our view of the evidence, that tide rises slowly.

We acknowledge that pipeline competition has benefited all ratepayers (gas and electric) by causing the cost of gas to drop and we recognize the threat of "bypass by wire" as new generators locate outside the reach of the RLS tariff. But those conditions do not change the fact that less throughput on the SoCalGas system means higher rates for all captive ratepayers on the system. Two things are assured should the RLS tariff be immediately abolished: (1) the large noncore users on SoCalGas' system will migrate to the Pipelines for baseload and take peaking service from SoCalGas, and (2) the captive ratepayers of SoCalGas will pay higher rates.

The tension between competition, the revenue requirement, and the burden of responsibility for the revenue requirement (ratepayers or shareholders) has not been lessened between 1995 and the present. The evidence in this proceeding shows significant changes in regulation over the recent past, but those changes do not provide a basis for us to predict that abolishing the RLS tariff immediately will bring the same benefits to gas ratepayers that pipeline competition has brought. There is evidence that since pipeline competition was initiated gas prices have been reduced. However, the Pipelines' contention that if large users leave SoCalGas' system ratepayer costs will lessen is speculation. It is an anomalous situation that a market based peaking tariff has no customers. But precipitously removing the RLS tariff in this BCAP without ameliorating the effects of the abrupt change assures higher rates for captive customers.

What we have described are the short-term effects of removing the RLS tariff. However, it is apparent to us that in the long term the RLS tariff's detriments will outweigh its benefit. There is no doubt the game is changing. Gas and electric industry restructuring should not be impeded by attempts to reconcile new conditions to past economic theory; rather, theory must be modified to encompass the emerging changes. At this time we are confident that the RLS tariff keeps rates down for all SoCalGas customers, except those who would partially bypass. But, the evidence persuades us that perpetuating the RLS tariff will have the pernicious effect of causing an increase in rates resulting from throughput being substantially reduced as SoCalGas is bypassed by new large customers. SoCalGas' own forecast shows a decline in electric generation throughput from 285.4 MMDth in 1999 to 226.8 MMDth in 2001, a drop of over 20%; and a drop in noncore C&I throughput from 147.0MMDth in 1999 to 137.1 MMDth in 2001. Those opposing the RLS tariff attribute this drop, in part, to the effect of the tariff barring new entrants and forcing relocations. Although the RLS tariff can lock in customers now located in SoCalGas' territory, it is expected to cause potential customers to locate outside the territory. SoCalGas is fighting the concerns of 1995; we must resolve the current issues of energy restructuring.

Nor should we take a parochial view of gas regulation. In adopting a Sempra-wide EG rate we were persuaded that it is in the public interest to consider the effect level transportation rates would have on PX prices for electricity and the resulting effect on electricity purchasers. In regard to the RLS tariff our reach is further than gas costs for electric generation; we take cognizance of the effect of gas costs on large industrial gas users. We should not be in the business of discouraging low costs.

The Pipelines and other argue that the RLS tariff is anticompetitive. We are not persuaded. Competition can take many forms. There is the competition between pipelines: SoCalGas v. Pipelines. One would expect that two competitors would compete based on price, quality of service, meeting customers needs, better product, etc. But what the evidence shows is that Pipelines refuse to compete on the basis of quality of service. Customers want peaking service; Pipelines say peaking service is uneconomic for them. It is not SoCalGas that refuses to compete; it is Pipelines. We accept Pipelines' assertion that it is uneconomic to increase the capacity of their pipes to provide peaking service. That is their choice and they should not be heard to complain. Faced with the choice of improving service by increasing capacity or attempting to persuade the Commission to change SoCalGas' tariffs, Pipelines chose the cheaper route: try to persuade the Commission.

From the customers' viewpoint the competition is different. Here there are two choices: SoCalGas or Pipelines. The customer without a peaking requirement has a routine choice based on price, quality of service, etc. Clearly there is a competitive choice. The customer with a peaking requirement has a problem. It can accept SoCalGas for full service; it can abandon its peaking requirement and choose based on price etc.; it can move out of SoCalGas' territory or not enter in the first place; or it can persuade the Commission to abolish the RLS tariff. The choice is economic. By coming to the Commission these customers have, like the Pipelines, chosen the cheaper route.

In this equation we cannot exclude the captive customer of SoCalGas; the customer who has no choice of pipelines but is responsible for SoCalGas' revenue requirement. To the extent that customers with choice leave SoCalGas the remaining customers must absorb the lost contribution to margin. This raises a policy question regarding the efficiency of the RLS tariff which we have heretofore consistently resolved in favor of retaining the tariff.

So, we do not believe the RLS tariff harms competition between pipelines; and we believe customers with peaking needs have alternatives that do not require abolishing the RLS tariff. But we are deeply concerned with the effect of the RLS tariff's driving large users out of SoCalGas' territory and inhibiting large users from entry. This directly impacts captive customers. Apparently SoCalGas, as it defends the RLS tariff, doesn't see the tariff as the cause of this migration, or, perhaps it doesn't care as it has the captive customers to fall back on. However, we are especially concerned with the effect of rates on captive customers. We must attempt to stem the erosion of throughput while not relinquishing the value of a peaking tariff. Consequently, we continue the RLS tariff for one year while giving SoCalGas the opportunity to propose a peaking tariff. SoCalGas shall file an application for proposed peaking rate tariff within 60 days of the effective date of this decision.

In our opinion the RLS tariff should be replaced simultaneous with the effective date of a new peaking tariff. It is our intention that this occur within one year of the effective date of this decision. This will give all parties the opportunity to determine how best to position themselves in the post-RLS tariff world. We must allow SoCalGas to make such modifications to its tariffs as are necessary to allow it to compete effectively with the bypass pipelines. There are significant differences between FERC tariff rates based upon straight-fixed variable rate design and SoCalGas' existing all-volumetric rates. All volumetric rates put SoCalGas at an inherent disadvantage in a partial bypass situation. Absent the RLS tariff, the different rate structures offered by SoCalGas and bypassing interstate pipelines would provide an unjustified advantage to customers that partially bypass SoCalGas. SoCalGas asserts it is willing to engage in a fundamental reexamination of its rate design if the RLS tariff is abolished. We agree that SoCalGas should be permitted to propose a revision of its volumetric rate design. We express no opinion on the content of a proposed peaking tariff, except that it not be the equivalent of the RLS tariff.

XVI. Regulatory Balancing Accounts

ORA recommends that all balancing accounts be updated effective January 1, 2000, to coincide with the implementation of new BCAP rates. For its presentation in this proceeding, ORA has generally used the balancing account estimates presented by the company. Two exceptions are the ITCS account and the PITCO/POPCO transition cost account. For the ITCS account ORA used an estimate of $72.4 million on the assumption the 1996 rehearing proceeding would result in a reallocation of surcharges to the noncore. SoCalGas used an estimate of $24.5 million for this account. For the PITCO/POPCO account, ORA assumed a zero balance since the costs should be fully amortized by the end of the year.

In D.99-11-021, we ordered the reallocation of $88.1 million in El Paso and Transwestern surcharges. The surcharges at issue in D.99-11-021 resulted from settlements approved by the FERC in the pipelines' last general rate cases.[14] In our final decision in the SoCalGas 1996 BCAP, D.97-04-082, we allocated the pipeline surcharges between SoCalGas' core and noncore customer classes in proportion to the amount of pipeline capacity reserved for the core and the amount of excess capacity formerly reserved for the noncore, the cost of which is now recovered through ITCS. On rehearing of D.97-04-082, we ordered the

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[14] See *El Paso Natural Gas Co.*, 79 FERC ¶ 61, 028 (1997); and *Transwestern Pipeline Co.*, 72 FERC ¶ 61,085 (1995).

reallocation of $88.1 million in surcharges, the majority of which are to be reallocated to the noncore through a special ITCS subaccount. (D.99-11-021, *mimeo,* at 61 (Ordering Paragraph 1).) We deferred to this proceeding the determination of the appropriate period for amortization of the regulatory account balances affected by the reallocation. (Id. Ordering Paragraph 2.)

As shown in Exhibit 208, approximately $14 million of the $88.1 million in reallocated surcharges have yet to be billed to SoCalGas. The amortization period for that $14 million is not at issue here since those costs will be allocated to the regular ITCS account and amortized the same as the other transition costs allocated to the ITCS. The remaining $74.1 million in surcharges reallocated to the noncore are the subject of this decision. That $74.1 million is reduced by $3.2 million in El Paso credits, leaving the net reallocation to the noncore at $70.9 million, plus interest. The total shift to the noncore is $79.9 million to be recovered through the special ITCS subaccount. The appropriate amortization period for that $79.9 million is in issue. For the reasons discussed below, the $79.9 million in surcharges and interest costs allocated to the special ITCS subaccount will be amortized over a one-year period ending December 31, 2000.

SoCalGas recommends a one-year amortization period. SoCalGas' recommendation is supported by SDG&E, ORA, TURN, EGA, and SCGC. A four-year period is recommended by SCE, Watson, and CIG/CMA.

At this time the noncore ITCS account is overcollected by $50 million plus. The current noncore ITCS surcharge is $0.01527/th. A one-year amortization of the $79.9 million, after offset of the overcollection, will reduce the surcharge to $0.00793/th. The parties most affected by the surcharge — SoCalGas and SCGC -- support one year, as do ORA and TURN.

SCGC's members, which are among SoCalGas' largest customers, have a greater interest than other noncore customers in the length of the amortization period as they will pay more of the reallocated surcharges than any other individual customers. SoCalGas has a significant interest in the length of the amortization period because the longer the surcharge reallocation impacts noncore rates, the longer SoCalGas will face an increased risk of uneconomic bypass. SoCalGas wants the recovery of the surcharges from noncore customers to be over as quickly as possible so as to minimize its exposure to potential bypass. This, of course, will benefit the core.

SCGC asserts the longer the amortization period, the more interest costs that the noncore will be required to pay on the reallocated surcharges. Moreover, the longer the reallocated surcharges impact noncore rates, the longer that southern California electric generators will be at a competitive disadvantage vis a vis generators located outside of SoCalGas' service territory.

SCGC argues that SCE, which advocates a longer amortization period, will indirectly benefit from artificially prolonging the amortization period. The longer the period over which the surcharges are amortized, the less impact the surcharge reallocation will have on current noncore rates, including the rates paid by SoCalGas' EG customers. SCE stands to benefit from minimizing the reallocation's impact on EG rates to the extent that lower EG rates translate into lower market-clearing prices for electricity during the legislative freeze on electric rates. The less that SCE pays for electricity, the more head room it has for the recovery of Competition Transition Costs (CTCs) during the rate freeze period. The more CTCs that SCE recovers now, the less exposure SCE will have for liabilities after the rate freeze ends. In any case, because SCE has no gas-fired generation it will not be paying the surcharge.

CIG/CMA recommends a four-year surcharge amortization period, supported by Watson. Their argument is that the longer the amortization period the lower the overall noncore rates. Further, a one-year period will cause a sharp drop in ITCS at its end; a four-year period will cause a relatively stable charge for four years. These parties want the current $50 million plus overcollection refunded promptly, in one year, and the surcharge spread over four years. Watson frankly admits the four-year period will give it a source of cheap money.

In our opinion a one-year amortization period is much preferable than four years. It promptly recovers an extraordinary charge, it shortens the wait for a more competitive rate, and it lessens the interest costs to ratepayers. ORA should audit SoCalGas' regulatory balancing accounts during the BCAP period.

XVII. Cost Allocation

A. Marginal Cost Estimation

All marginal cost issues have been addressed in earlier sections of this decision.

B. Establish Base Margin

In the SoCalGas' PBR proceeding, ORA recommended that $14 million in capital costs associated with the construction of Lines 6902 and 325 be excluded from ratebase. This recommendation was based upon provisions of the Global Settlement requiring that all capital costs relating to increases in noncore load be placed below the line. This treatment was to remain in place so long as the ratemaking treatment in the Global Settlement remained in effect. (D.97-07-054, Slip Opinion, p. 78.) Since the Global Settlement expired in August, SoCalGas is proposing to include these capital costs in ratebase. This would increase the revenue requirement by approximately $2.66 million. ORA has no objection to including these costs in rate base now that the Global Settlement has expired.

SoCalGas proposes to eliminate the existing zone rate credit and roll in the revenue requirement associated with the Wheeler Ridge interconnection facility, which will create an annual revenue requirement increase of $6.83 million per year. The justification for rolling in the Wheeler Ridge revenue requirement is discussed in Section X. SoCalGas' proposal will be adopted.

C. Allocation of Base Margin

The marginal cost revenue is developed by taking the marginal costs for each function, such as distribution or transmission, and multiplying it by the MDM. In general, the MDMs are the forecasts of throughput which drive investment decisions to meet anticipated demand. For instance, the MDM for the distribution system is the coincident peak month demand, while the MDM for the transmission system is the cold year throughput. In this BCAP, SoCalGas used its 1999 throughput forecast for the MDMs while ORA used the average throughput of years 2000, 2001, and 2002.

The sum of the marginal cost revenue from each of the functional categories (customer, distribution, transmission, and storage) determines the total marginal cost revenues. Rarely, if ever, will the marginal cost revenues match the total authorized gas margin (revenue requirement). A scaling function is performed so that total revenue collected from the customers will meet the authorized gas revenue requirement. The ratio of the marginal cost revenue for each customer class versus the total system marginal cost revenue determines the EPMC scaler. For example, if the core class is responsible for 80% of the marginal cost revenues, it will be allocated 80% of the revenue requirement.

There is no dispute between the parties regarding the methodology for allocating the base margin. The differences are the result of different marginal cost estimates as well as different throughput assumptions. In addition, ORA included the throughput for both Rosarito and DGN (Mexicali) in its forecast.

Including Rosarito throughput for cost allocation purposes is consistent with D.99-09-071, where the IB tariff was rejected. Including DGN throughput is consistent with the Commission finding in D.98-12-024 that the contract rate should be the sum of the LRMC and any exclusions and that SoCalGas should be responsible for any shortfalls. The throughput associated with discounted contracts are typically included in the forecast for cost allocation purposes.

D. Allocation of Non-base Margin Costs

All regulatory balancing account balances have been updated and will be included with the implementation of new BCAP rates. ORA has generally relied upon the balances depicted in the SoCalGas application with the following exceptions.

- ORA estimated ITCS costs at $72 million to reflect the ORA recommendation in the 1996 BCAP rehearing that the Transwestern and El Paso surcharges be reallocated to noncore customers.

- ORA allocated exclusions (transition costs) to DGN consistent with the Commission's decision in D.98-12-024.

- ORA removed the Rosarito credit revenue consistent with its recommendation that Rosarito shippers pay a full cost of service rate.

We have adopted the ORA recommendations with ITCS costs as modified by this decision.

E. Care and DAP

1. CARE Costs

CARE program costs, with certain exceptions, are recovered from all customers on an equal-cents-per-therm basis. Ultramar proposes placing a cap on the recovery of CARE costs from SoCalGas' largest industrial customers. It recommends a cap of 15 million therms per year which represents the average annual usage for transmission level G-30 customers. According to its witness:

> CARE costs are categorically different from SoCalGas' other costs. CARE is a social program designed to provide economic assistance to low-income customers. As such, the costs represent a Commission-sanctioned cross-subsidy of one group of customers by another. There is no sense in which customers such as Ultramar are receiving something of economic value here in exchange for each therm delivered. Indeed, under SoCalGas' proposed allocation method the reverse is true. The cost borne by the subsidizing shipper grows with each therm delivered.

ORA contends that this argument does little more than state the obvious since an equal-cents-per-therm allocation always results in larger customers contributing more than smaller customers. Nevertheless, this is the allocator the Commission has traditionally chosen to spread the recovery of costs that no one wants to pay. It doesn't matter if the costs relate to social programs or are some type of transition cost resulting from the restructuring of the gas industry. The point is not how much of the CARE program costs are being borne by the largest customers on the system. The point is, ORA argues, that an equal-cents-per-therm allocator has been considered a fair means of recovering costs for well over a decade and there is no need to create an exception now.

Of SoCalGas' approximately 1,194 noncore commercial/industrial customers, eight of them (including Ultramar) have annual gas usage exceeding 15 million therms representing approximately 37% of the total noncore G-30 load and 37% of the noncore CARE costs under the current CARE allocation methodology. The proposal by Ultramar of placing a 15 million therm cap on the CARE surcharge would reduce the eight customers' CARE responsibility from 37% to 14%, and result in a $1 to 2 million shift of CARE costs from G-30 customers to core customers.

Ultramar has not convinced us that the eight largest users on SoCalGas' system should pay proportionately less than everyone else to meet the costs of a social program. Its request is denied. We adopt ORA's recommendation.

2. DAP Costs

SoCalGas proposes to assign all $18 million in DAP costs to residential customers. TURN objects to this allocation and instead recommends that they be treated like CARE costs and allocated on an equal-cents-per-therm basis. ORA takes no position on this issue.

TURN maintains that SoCalGas' allocation is contrary to the statutory requirements of §§ 739.1 and 2790(a). It says DAP encompasses what is traditionally knows as "weatherization," as authorized by § 2790(a):

> The commission shall require an electrical or gas corporation to perform home weatherization services for low-income customers, as determined by the commission under Section 739, if the commission determines that a significant need for those services exists in the corporation's service territory, taking into consideration both the cost effectiveness of the services and the policy of reducing the hardships facing low-income households.

TURN argues that by statutory definition, DAP is a program of assistance to low-income electric and gas customers. Section 2790(a) specifies that eligibility is determined as under § 739, which stipulates in § 739.1(a) that:

> The commission shall establish a program of assistance to low-income electric and gas customers, the cost of which shall not be borne solely by any single class of customer. The program shall be referred to as the California Alternate Rates for Energy or CARE program.

This broad cost allocation has traditionally been applied to the CARE program, but it should be applied to the DAP program as well, in TURN's opinion, because DAP is designed to serve exactly the same ratepayers as CARE. The purpose of both programs is to serve the social and equitable goal of promoting affordable rates, not just to promote conservation or business goals.

SoCalGas points out that TURN has attempted previously to redirect the responsibility for DAP costs from residential customers to a broader base of customer classes in the 1993 BCAP proceeding. This issue was resolved in the JR by adopting the SoCalGas position.

F. DGN Contract

SCGC argues that the rate treatment of SoCalGas' long-term gas transmission service contract with Distribuidora de Gas Natural de Mexicali (DGN), a Sempra affiliate, should be consistent with the rate treatment of SoCalGas' other wholesale customers. Specifically, SCGC declares that SoCalGas be required to use the same LRMC methodology for allocating costs to DGN that it uses for its other customers.

In our decision approving the DGN contract, we determined that "after the Global Settlement period is concluded, the DGN contract should be allocated costs similar to that of a wholesale customer, including the cost of exclusions." (D.98-12-024, slip op. at Finding of Fact 18.) However, SoCalGas has failed to include any portion of the $4.5 million in exclusive use facilities dedicated to Mexicali service in its proposed customer cost LRMC for DGN. SoCalGas intends to treat the DGN pipeline extension facilities as incremental facilities.

SCGC recommends that SoCalGas be ordered to increase the customer cost LRMC for DGN by $457,021 to reflect the costs of the Mexicali exclusive use facilities. SCGC's recommendation will not be adopted. The allocation "similar to that of a wholesale customer" in this proceeding is a marginal cost allocation based on the NCO method, which is $22,034, and is adopted.

XVIII. Rate Design

A. Residential Rate Issues

There are five disputed residential rate design issues. The issues arise from SoCalGas' proposals to: (1) increase the $5 customer charge to $7 for most customers; (2) narrow the differential between Tiers I and II; (3) reduce the baseline quantities; (4) redefine the master meter class to include all master meter customers with an annual usage of at least 100 Mth; and (5) complete the deaveraging of residential and commercial rates. ORA recommends that the Commission retain the current $5 customer charge; reject the narrowing of the tier differential; maintain the current winter baseline allowance while slightly reducing the summer allowance; and reject the proposed change in the definitions of the master meter class. Finally, ORA supports eliminating core averaging, to be achieved gradually over the course of the BCAP. Each of these issues is addressed below.

1. Customer Charge

SoCalGas proposes to increase the residential customer charge from $5 to $7. It claims that the current customer charge collects only 50% of the annual residential long run marginal costs which it estimates at approximately $120. ORA reminds us that this represents SoCalGas' third attempt to increase the customer charge above the $5 level. SoCalGas, in its last BCAP, proposed increasing the customer charge to $7.12 for single family dwellings and $5.26 for multi-family dwellings. In its PBR application it proposed increasing the charge to $13.57 for single family dwellings and to $10.35 for multi-family dwellings. In each instance, the proposal was rejected in favor of the status quo. ORA believes the same consistent policy should be maintained in this case.

ORA points to numerous problems with the SoCalGas proposal. First, the company overstates its case when it claims that the current customer charge recovers only 50% of marginal costs. SoCalGas' estimate of $120 is based on the rental method for estimating customer marginal costs. A $7 charge would recover 70% of this estimate. The NCO method results in a significantly lower marginal cost of $78 per year. The current $5 customer charge recovers almost 77% this cost. Since the current customer charge recovers a greater percent of marginal costs under the NCO method (77%) than the $7 charge under the rental method (70%), ORA says there is no need for an increase.

Second, the company's proposal results in significant bill impacts to residential customers. SoCalGas' overall showing would result in a 3.16% decrease to the residential class. At the same time, its rate design proposals will result in a bill increase for 66% of single family customers with some increases as high as $24 per year. Over 50% of regular residential and low income CARE customers would receive a bill increase rather than a decrease. Providing an overall decrease to the class while providing most customers with a bill increase is simply not justified.

Third, the claim that the current customer charge results in high usage customers subsidizing low usage customers can't be substantiated. SoCalGas made a similar claim about cross-subsidies in its last BCAP, which was rejected. (D.97-04-082, Slip Opinion, p. 116.) Because nothing new has been added, the alleged claim of cross-subsidization should again be rejected.

In any event, ORA argues, the claim of cross-subsidization is outweighed by equity considerations. What SoCalGas is proposing amounts to a 40% increase in the customer charge. A low usage customer facing an increase of that magnitude has very little ability to control or lower the bill other than to stop taking service. A high usage customer, on the other hand, has more options for controlling the bill impact by reducing usage.

We agree with ORA. A 40% increase in the customer charge which provides access to a commodity which is essential to basic human comfort and safety is not warranted, particularly considering that neither PG&E nor SDG&E have customer charges. The final reason for rejecting the proposed increase in the customer charge is that it would result in a rate structure that violates the provisions of § 739.7, which requires an inverted rate structure.

2. Tier Differential

Section 739(c) requires the Commission to establish "baseline rates" which apply to the lowest block of an increasing block rate structure. The statute is premised on the principle that "electricity and gas are necessities, for which a low affordable rate is desirable." (§ 739(c)(2).) Section 739.7 similarly requires an "appropriate inverted rate structure". These code sections have been consistently interpreted to include the customer charge in determining whether the rate structure is, in fact, inverted. Under this "composite tier differential" approach, customer charges are considered part of the Tier I, or baseline, rate for the purpose of calculating tier differentials. (D.87-12-039, 26 CPUC2d 213, 270; D.89-01-055; D.97-04-082, pp. 117-118.)

SoCalGas currently has a differential of 35% on a fully bundled basis (including the gas commodity cost and excluding the customer charge) and is proposing to reduce it to 20% on an unbundled basis (excluding both the commodity cost and customer charge).[15] ORA argues the proposal must be rejected because when the customer charge is included, the rates are no longer inverted.

SoCalGas argues it is appropriate to decrease the differential between Tier 1 and Tier 2 volumetric rates. It proposes to reduce the differential from 35% to 20%. It says the present distorted residential rate design, consisting of a low customer charge and a high tier differential, is an ineffective and inappropriate tool for providing subsidized service to low income customers. What the existing rate design accomplishes is only to subsidize low volume users and not low income users. Consequently, the current residential rate design results in excessive subsidies going to low volume, high income users.

SoCalGas believes subsidies that exist as a result of a high tier differential cannot be justified on the basis of compassion for low income customers. It says the Commission has indicated its misgivings about the current baseline tier differential structure because it perceives inherent conflicts between the types of innovative service offerings that could be provided in a competitive market and using a regulatory-mandated rate design approach. (D.95-12-063 (1995) 64 CPUC2d 1 at 75.) SoCalGas asserts that a move to a 20% simple tier differential is consistent with the Commission's objective of moving towards cost-based rate design as well as with the language in § 739(c) which calls for a gradual differential between the baseline and Tier 2 rate. It admits the 20% tier

[15] Because of a change in methodology, SoCalGas' proposal to close the tier differential is greater than first appears. On a fully bundled basis, SoCalGas is actually proposing to reduce the differential to 10%.

differential is based upon maintaining the customer charge as a separate increment of customer rates, not included in Tier 1 rate.

We reject SoCalGas' proposal. As we said in the last SoCalGas BCAP,

> Therefore, we should retain the existing tier differential calculated on a composite basis. The composite tier differential is more meaningful than the simple differential because it gives the price for access and purchase of a quantity of gas that covers basic needs. (D.97-04-082, p. 118.)

No evidence has been presented that requires a different result. SoCalGas' statement that "a high differential cannot be justified on the basis of compassion for low income customers" flies in the face of § 739 which is specifically directed toward the low income ratepayer and which requires an inverted rate structure. We will adopt a 5% composite tier differential (excluding gas costs) as proposed by TURN.

3. Baseline Allowances

SoCalGas recommends reducing the summer baseline allowance from 15 therms per month to 14 therms per month, and the winter baseline allowance from 50 therms per month to 49 therms per month. ORA supports reducing the monthly summer baseline allowance to 14 therms since it would bring the allowance closer to compliance with § 739(d)(1), which requires that the summer baseline quantity be between 50% and 60% of average residential consumption. ORA opposes the reduction in the winter allowance since the current allowance is already in compliance with the statute. The statute requires that the winter baseline quantity be set between 60% and 70% of average residential consumption. The current winter allowance represents 69.3% of average residential consumption. Since it is already in compliance with the statute, there is no need for a change.

SoCalGas says ORA ignores that under the existing winter allowance of 50 therms, the proportion of throughput billed at the Tier 1 rate is 69.3% in the winter, on the verge of exceeding the statutory limit. SoCalGas' proposed adjustment to 49 therms as the winter allowance is extremely modest and will serve to better ensure compliance with Pub. Util. Code § 739(d)(1). Even at SoCalGas' proposed winter allowance of 49 therms, the proportion of overall residential throughput billed at the Tier 1 rate is expected to be 68.5% in the winter, only 1½% away from the upper limit specified in the statute. We will adopt SoCalGas' proposal.

4. Core Deaveraging

Over the past two BCAPs the Commission has pursued a policy of deaveraging commercial and residential rates. In the 1993 BCAP, the Commission deaveraged core and commercial rates by 50% over the two year BCAP cycle. In the 1996 BCAP it again deaveraged rates by 50%. As a result of these two decisions, 75% of the effects of averaging have been removed from commercial rates. SoCalGas proposes to eliminate the remaining $28.4 million in averaging costs from commercial rates in the first year of the BCAP. TURN opposes further deaveraging in this BCAP. This issue was resolved by the JR, by maintaining the status quo.

5. Master Meter Issues

a. Requirement for Service

SoCalGas proposes to lower the requirement for taking service at the residential master meter rate from 250Mth of annual usage to 100Mth of annual usage. This would increase the number of master meter customers (who pay lower rates) and thus would increase other residential rates. SoCalGas states that these customers are paying more than their fair share of marginal customer costs. In making its argument, SoCalGas calculates marginal customer costs using the rental method.

ORA opposes this recommendation as it would raise the rates for other residential customers and because the change is unnecessary at this time. The master meter sub-class was recently created in SoCalGas' last BCAP, D.97-04-082, and there is no need to change the class definition for master meter customers so soon. Also, ORA uses the NCO method to calculate marginal customer costs. When this method is used to calculate marginal costs, SoCalGas' argument that large customers are paying far more than their share of marginal customer costs is weakened.

Master meter customers are a diverse group. The number of living units per master meter varies widely. Some accounts have over 1,000 units per master meter. However, more than 45% of the master meter accounts have three or less living units and 57% have 4 or less units. Given the substantial number of master meter accounts with such a small number of living units, SoCalGas proposes to include the smaller customers within the single family customer class for establishing the monthly customer charge. Under SoCalGas' proposals, small master meter customers with annual usage of less than 100 Mth would pay a monthly customer charge of $7. Under current rates, a master meter customer using 100,000 therms will pay over $11,000 per year in customer-related costs through its volumetric rates while having marginal customer costs of approximately $4,400 per year. This is a significant discrepancy and segmenting the master meters at 100 Mth instead of the current level of 250 Mth will help remedy this. Consistent with the policy established in D.97-04-082, the customer charge for this segment will be cost based, calculated to recover the marginal customer related costs. The impact of implementing this proposal on other residential customers is less than $1 per year.

Western Mobilehome Parkowners Association (WMA) supports SoCalGas. Under current tariffs a customer using 100 Mth will pay an extra $2,600 in customer-related costs more than its cost of service. Changing the definition of large master meter customers to an annual usage level greater than 100 Mth provides relief for a large group of customers, and shifts costs of only an additional $.90 per year for an average residential customer, with only a $.40 per year impact for a small multifamily customer. This cost shift reverses in part the cross-subsidy that these large customers now provide to all other residential customers.

We agree with SoCalGas and WMA. Lowering the threshold to 100 Mth therms per year is a reasonable change, well justified with limited cost impacts on other customers, and will be adopted.

b. Submeter Credit

SoCalGas makes several proposals related to the submeter credit. Under current rate design, a submeter credit is given to customers with master meters who provide metered service to residential sub-units, for example at multifamily dwelling units and mobile home parks. The purpose of the submeter credit is to compensate the master meter customer for costs of providing submeter services. The compensation to the master meter customer is based on the costs avoided by SoCalGas in serving one master meter customer rather than the individual units served through the master meter.

SoCalGas proposes to retain the master meter avoided costs that were adopted in D.97-04-082, but to revise the methodology used to calculate the submeter credit in two ways. First, SoCalGas proposes that the submetered units be treated as single family dwellings. Almost 90% of submetered units are in mobile home parks, and those facilities and physical configurations closely align with single family premises. Under SoCalGas' proposal, submetered units would be charged the $7 per month customer charge applicable to single family dwellings. Second, to be consistent with Commission policy on unbundling, SoCalGas proposes to eliminate the scaling component of the submetered calculation. This is because costs included in the scaler are non-marginal costs and therefore not avoided by SoCalGas as result of master-metering. SoCalGas proposes to eliminate this and have the avoided costs used in the calculation of the submeter credit be consistent with the avoided cost policy adopted by the Commission for unbundling. The new avoided cost figure would be $9.86 per month, and the new submeter credit would be $2.86 per month.

WMA agrees with SoCalGas' master meter proposals except the proposal to eliminate the scaler. WMA argues that there are strong policy arguments for applying the EPMC scaler to determine the SoCalGas master meter discount. First, the express language of § 739.5 requires that the differential be set at a level that reflects the utility's average cost of supplying the service. The rates charged by the utility at the master meter are scaled to reflect the full SoCalGas revenue requirement. That revenue requirement is SoCalGas' cost of providing the service. WMA contends that setting the master meter differential at a lower level through omission of the scaler puts the master meter customer in a price squeeze: it pays a rate at the master meter which is based on full cost recovery by the utility, but it is permitted less than full cost recovery for the service it provides to the submetered residents and which the utility is permitted to avoid. The utility would be in a position of recovering costs as if it had incurred them, while paying the actual provider of those services a smaller amount. This violates the principle of utility indifference embedded in § 739.5. It converts master metered delivery service into an inappropriate profit center.

WMA estimates the avoided cost credit is $.3804 per day or $11.58 per unit per month. Scaled, the credit is about $.47 per day.

SoCalGas responds that the scaling performed in SoCalGas' cost allocation process reconciles marginal cost revenues for the SoCalGas system to the authorized level of costs. The scaler adjusts the system marginal cost to the system average cost, not the costs of any one particular functional activity. The marginal costs used to develop the avoided costs include loaders that are placed on the O&M costs that reflect overhead cost. The marginal capital costs reflect all of the capital related costs: return, depreciation, and taxes. An avoided cost calculation, as the Commission has determined in the unbundling proceedings, should not include the scaler. SoCalGas recommends adopting the WMA credit of $.3804/d, without the scaler.

Section 739.5(a) provides, in part:

> The commission shall require the corporation furnishing service to the master meter customer to establish uniform rates for master meter service at a level which will provide a sufficient differential to cover the reasonable average costs to master meter customers of providing submeter service, except that these costs shall not exceed the average cost that the corporation would have incurred in providing comparable services directly to the users of the service.

We agree with WMA. The scaler should be included in costs; the credit should be approximately $.47 per day per unit. In SoCalGas' last BCAP the scaler was included in costs and SoCalGas has not persuaded us that we should now drop it. If SoCalGas provided the service it would have priced it including a scaler. There is an unreasonable imbalance when SoCalGas collects revenue based on costs that include a scaler, but argues that those costs are different (and less) when SoCalGas must pay.

B. Core Commercial/Industrial Rate Issues

SoCalGas currently has two commercial and industrial classes. The G-10 class is comprised of customers using less than 250 Mth per year while the G-20 class includes all customers using more than 250 Mth per year. In its direct testimony, SoCalGas recommended combining these two classes into a single class with a 3-tiered rate design structure. Under this proposal, the commercial class as a whole would experience a rate decrease. However, smaller customers using less than 2,500 therms per year would experience a bill increase. In its direct showing, ORA indicated it could support the SoCalGas proposal provided that the customer charge for smaller commercial customers (those using less than 1000 therms per year) was reduced from $15 to $10 per month. Adoption of this modification to the SoCalGas proposal would result in a commercial rate design similar to the one currently in effect for PG&E. Both TURN and SoCalGas support this modification. SoCalGas, ORA, and TURN have proposed a new consolidated core commercial and industrial customer class, tariff, which we adopt.

We will adopt the proposal to combine the G-10 and G-20 customer classes. SoCalGas will be authorized to file an advice letter as it proposes.

C. Noncore Commercial and Industrial Rate Design

1. Rate Design

SoCalGas' current noncore commercial and industrial rate design distinguishes between medium-pressure and high-pressure distribution customers. The company proposes to simplify its rate design by eliminating this distinction. This would result in two subclasses of G-30 customers, those served at the distribution level and those served at the transmission level. SoCalGas additionally proposes a single customer charge and a declining block rate structure, which will avoid some of the rate discrepancies currently experienced by customers with similar usage. ORA recommends that the changes proposed by the company be adopted. We agree.

2. Special Treatment for Red Team and Rule 38 Contracts

SoCalGas proposes to exclude the additional throughput resulting from two categories of discounted contracts from cost allocation proceedings for a five-year period. The two categories involve shareholder funded incentives to attract new load under the state authorized "Red Team" economic development effort and the Commission approved "Rule 38" program. The latter program is aimed at stimulating interest in new gas fired technology.

Under current practice, the additional throughput resulting from discounted contracts entered into over the course of a BCAP period would be included in the forecast adopted in the next BCAP. If the Commission were to adopt a three-year BCAP, as recommended by ORA and others, shareholders would benefit from the additional revenues associated with Red Team and Rule 38 contracts for a three-year period. Ratepayers would benefit from the additional load in subsequent BCAPs since the company's costs would be spread over a larger volume of throughput. SoCalGas is essentially proposing to extend the period during which shareholders benefit from three years to five years.

ORA objects to this proposal. Any changes in the incentives for shareholder participation in Red Team and Rule 38 programs should similarly be addressed in the context of the PBR since that is the proceeding which examines the overall incentive structure. The JR resolves this issue by accepting SoCalGas' proposal.

D. Rate Design Window

Rate design issues are typically examined during the course of each BCAP. SoCalGas proposes to change this practice by making a "rate design window" filing in April 2000 for rate design changes which would take effect on January 1, 2001. SoCalGas claims that the transition to a new regulatory structure requires a mid-course rate design proceeding.

ORA says this proposal is inefficient, unnecessary, and should be rejected. Based on the current schedule, it is unlikely that new BCAP rates and rate design changes will be implemented much before February 2000. SoCalGas is proposing to file a new application two months later to litigate rate design issues yet again. This is simply an inefficient and wasteful use of the Commission's and other parties' limited resources, in ORA's opinion. Any rate design changes which SoCalGas thought were necessary during the upcoming BCAP period, should have been addressed in its testimony. Neither ORA nor other parties have the resources to address whatever rate design changes the company can propose on an annual basis. We agree with ORA.

E. Impact of the Joint Recommendation

The JR impacts core deaveraging and the incentives associated with Red Team and Rule 38 contracts. The JR would adopt the TURN position that no further deaveraging take place during this BCAP cycle. It would also adopt the SoCalGas position that the additional throughput from Red Team and Rule 38 contracts be excluded from the cost allocation process for a five-year period. ORA believes that these compromises are reasonable in the overall context of the JR. ORA argues that while the Commission is clearly committed to eliminating the subsidies inherent in the core averaging process, it is also true that SoCalGas is much farther along in the process than PG&E, having already eliminated 75% of the subsidy. Given this, delaying the full elimination of averaging to the next BCAP is reasonable. Delaying the benefits to ratepayers from additional throughput from Red Team and Rule 38 contracts is also reasonable given other provisions of the JR which benefit ratepayers including the higher throughput forecast.

XIX. Other Issues

A. PBOP

Commission policy requires SoCalGas to return PBOP overcollections to ratepayers. SoCalGas has incorporated $8,713,000 in PBOPs overcollection in rates by refunding that amount to ratepayers through an EPMC allocation. ORA agrees, as do we.

B. Customer Satisfaction Under 1997 PBR

In D.97-07-054, the Commission adopted the joint recommendation of SoCalGas, ORA, and TURN to conduct a mid-course evaluation of the service quality, customer satisfaction, and safety incentives of the SoCalGas PBR. The Commission identified the current BCAP as the appropriate forum for that review. SoCalGas has provided evidence on customer satisfaction, service quality, and safety measures, but since the PBR commenced on January 1, 1998, there is limited information available for making a reasonable assessment of the PBR measures in this proceeding. ORA agrees with SoCalGas that there is no reason to change the measures, targets, rewards and/or penalties established in the 1997 PBR decision. ORA also agrees that this is not the appropriate proceeding to establish a CARE performance measure, and recommends no such measure at this time. In its annual review of the SoCalGas PBR, ORA will monitor and evaluate the performance of SoCalGas in the areas of customer satisfaction, service quality, and safety.

C. QF Restructuring

SoCalGas claims that gas ratepayers are harmed as a result of QF restructuring. To remedy this harm it recommends the establishment of either an escrow account which would compensate gas ratepayers for any harm they experience or a tracking account to track revenue as a result of QF restructuring. ORA opposes the SoCalGas recommendation since there is no need for this account. The throughput risk developed as a part of the JR equitably balances shareholder and ratepayer interests and the EOR balancing account tracks revenue recovery associated with EOR contracts. We agree with ORA. Utilities have always had a risk factor incorporated into their rate of return. One risk is regulatory policy changes. This is not a surprise and does not require special treatment.

D. Interstate Pipeline Refunds

SoCalGas has received approximately $11.7 million in refunds from El Paso, Transwestern, and PITCO, an affiliate. ORA recommends that these refunds, plus interest, be returned to customers in conjunction with the implementation of new BCAP rates. The refund should be in conformity with the refund plan submitted with Exhibit 196. The return of the refunds to customers should generally follow the manner in which the interstate costs associated with the refunds were originally allocated to the different customer classes. SoCalGas agrees with this proposal. We will adopt the proposal; the refund should be amortized over a one-year period.

XX. Issues Local to SDG&E

Issues common to both SoCalGas and SDG&E have been addressed in earlier sections of this decision. The common issues include the length of the BCAP and forecast periods, marginal cost methodological issues such as the use of the NCO method for calculating customer marginal cost and the use of replacement costs adders for each of the demand functions, and the proposed single EG rate for both the SoCalGas and SDG&E systems. Issues unique to

SDG&E include throughput, the transmission resource plan, customer and distribution marginal cost estimates, and rate design.

SDG&E has entered into two written agreements with interested parties which are intended to narrow the remaining issues. The Joint Recommendation (SDG&E JR) between ORA, SDG&E, and UCAN is by far the more expansive of the two, offering proposed resolutions to virtually all of the disputes between these parties (Appendix B). Specifically, the SDG&E JR resolves various marginal cost and cost allocation issues, agrees upon a transmission resource plan, stipulates to throughput and revenue levels, and proposes a two part, two-tiered volumetric rate design for electric generators served by SDG&E.

The SDG&E JR does not present a proposed resolution to the question of whether the Commission should adopt a Sempra-wide EG rate, nor come to any conclusion on issues related to the Schedule IB tariff proposed in the SDG&E and SoCalGas application for approval of a gas transmission service (A.98-07-005), and rejected in D.99-09-071.

The second joint recommendation is between SDG&E and the Western Mobilehome Parkowners Association (WMA) (the WMA JR) concerning the master meter differential for SDG&E's mobilehome park customers (Appendix C). This is a narrow issue of only limited interest. WMA and SDG&E were the sole presenters in this matter.

SDG&E asserts that together, these two agreements offer a fair and reasonable resolution to the vast majority of disputed issues in SDG&E's 1999 BCAP. The parties ask us to recognize that these agreements were reached through intense negotiation and compromise. Parties were required to compromise their original positions. Accordingly, the parties view each agreement as a unified whole, with individual recommendations expressly conditioned upon Commission acceptance of all other recommendations.

A. Throughput Forecast

The SDG&E JR recommends that the Commission adopt ORA's annual fossil generation throughput forecast of 480 million therms for SDG&E's former UEG customers. This amount falls between the forecast arrived at using production cost modeling and analyzing recorded values. Production cost modeling provides a logical tool for forecasting UEG throughput. The model matches electrical supply with demand over a wide geographic area, and then predicts which facilities will be dispatched based on production costs and reliability requirements.

A trending of future throughput from recorded values offers a historic basis for the forecast. With much of California generation no longer owned by regulated utilities, the operating strategies of the new non-regulated utilities are difficult, if not impossible to model. In fact, there have been so many changes over the past 18 months in the California energy market generally, and with the SDG&E's fossil generation units in particular, that it is difficult to be confident that next year's gas usage will be anything like the prior years' usage.

The radically changing California energy market is reason enough for the Commission to adopt a compromise forecast between production modeling and historic trending. The deregulation of the California electric market dramatically changed the conditions under which electric generators must operate. Today, most generators bid into the competitive market operated by the PX to sell their energy and any associated ancillary services. The ISO has designated some generators as RMR units, meaning that they will be dispatched for reliability purposes if they are not dispatched in the marketplace.

SDG&E's fossil units have been sold to two separate companies, each with its own operating strategy. Given the fundamental transformation of the California market and the recent change in ownership of the SDG&E units, adopting a compromise forecast which is mid-way between production cost modeling and historic trending will achieve a fair outcome.

B. Resource Plan

The SDG&E JR recommends a $31 million gas transmission resource plan for SDG&E. This resource plan is a compromise between SDG&E's original proposal — a $25 million plan — and the $42.7 million plan ORA sponsored. The SDG&E JR adopts a plan that is roughly 25% more expensive than SDG&E's initial proposal and almost one-half of the 49% increase ORA recommended in its report.

C. Marginal Costs

1. Marginal Customer Costs

The SDG&E JR uses the NCO method for calculating customer marginal costs as advocated by ORA and UCAN. The Commission ordered SDG&E to use the NCO method in D.97-04-082, SDG&E's 1996 BCAP decision. The NCO method incorporates three main marginal cost components: (1) a one-time investment cost for new customers; (2) an annual investment cost of replacing customer service, regulator, and metering equipment; and, (3) customer related O&M expenses. The SDG&E JR reflects a compromise between positions originally taken by SDG&E, ORA, and UCAN on capital costs, O&M costs, and O&M loading factors.

The SDG&E JR also incorporates the following specific ORA and UCAN positions for calculating marginal customer costs:

a. Residential Customers

The SDG&E JR adopts UCAN's proposal for calculating marginal customer costs for the residential customer class.

b. Non-Residential Customers

The SDG&E JR adopts ORA's proposed new and replacement capital cost calculations and UCAN's recommended reduction of SDG&E's variable customer costs for: (1) returned checks and field collection charges; and, (2) service establishment fees. The SDG&E JR also adopts UCAN's proposed A&G O&M loading factor.

2. Demand Costs

The SDG&E JR maintains the status quo with regard to the demand-related marginal cost methodologies adopted in D.97-04-082. The SDG&E JR excludes ORA's replacement cost adder proposal for demand related marginal costs (distribution and transmission).

3. Distribution Marginal Costs

The SDG&E JR adopts ORA's proposed distribution marginal cost regression calculations and UCAN's A&G loading factor of 13.995%. The SDG&E JR adopts SDG&E's recommendation to exclude replacement cost adders. By adopting these compromise positions, the SDG&E JR produces lower distribution marginal costs than those originally proposed by SDG&E.

4. Transmission Marginal Costs

To develop transmission costs, the SDG&E JR uses the Commission-adopted methodology from D.97-04-082. Specifically, it adopts the total investment method with no replacement cost adder; assumes a $31 million total resource plan investment for calculating transmission marginal cost; and adopts UCAN's proposed 13.995% A&G loader.

In summary, the SDG&E JR reflects a blend of positions originally taken by SDG&E, ORA, and UCAN with regard to marginal costs, O&M costs, and O&M loading factors related to customer marginal costs. The SDG&E JR addresses UCAN's concern that residential marginal customer costs as proposed by SDG&E are too high. It addresses ORA's concern that some A&G expenses were "double counted" in SDG&E's capital cost calculation. The SDG&E JR also adopts ORA's assumptions concerning NCO replacement rates and replacement costs. And, although SDG&E's 1996 BCAP replacement cost assumptions would produce higher replacement costs under the NCO method than those proposed using the ORA's assumptions, the SDG&E JR adopts the ORA assumptions and calculations as part of the whole package.

D. EG Rate Design

The SDG&E JR produces a stand-alone EG rate design for SDG&E that is distinct and separate from the EG rate design (and EG charges) used by SoCalGas. The proposed rate design would divide SDG&E's EG customer class into two segments, with each part consisting of a single customer charge and two tiers of declining block rates. The "Part A" EG rates are applicable to individually metered EG loads of less than one million therms per month. The first block rate (Tier 1) under "Part A", applies to the customer's first 21,000 therms of usage per month. The second, lower block rate (Tier 2) applies to all excess usage.

The "Part B" EG rates are applicable to individually-metered EG loads equal to, or greater than one million therms per month. The Tier 1 rate under "Part B" applies to the customer's first one million therms each month. The lower Tier 2 rate applies to all excess usage. The SDG&E JR's EG rate proposal is based on the alternate EG ratemaking methodology proposed by SoCalGas adjusted to reflect SDG&E's customer usage characteristics.

Because we are adopting a Sempra-wide EG rate, this part of the SDG&E JR will not be adopted. The parties agree.

E. Sempra-Wide EG Rate

The SDG&E JR does not address the issue of whether the Commission should establish a uniform rate across both SDG&E and SoCalGas' service territories. The parties agree that if the Commission does adopt a Sempra-wide EG rate, the EG rate design of the SDG&E JR may be modified to comply.

F. Rosarito Loads

The SDG&E JR does not address the question of whether Rosarito loads should be included in SDG&E's proposed EG customer class (or an existing SDG&E customer class) for cost allocation purposes. The rates proposed in Exhibit 195 assume that Rosarito loads and costs are excluded. SDG&E concedes, however, if the Commission decides to include Rosarito loads and costs within one of SDG&E's proposed or existing classes, the SDG&E JR's IB class credit should be changed to zero. As we decided in D.99-09-071, the forecasted throughput for service at the international border should be included in both SDG&E's EG forecast and SoCalGas' wholesale forecast.

G. Marginal Cost Calculations

The SDG&E JR maintains the status quo for calculating marginal cost revenues and base margin costs, and for allocating base margin costs and non-base margin costs.

H. Core Deaveraging and Global Settlement Credits

The SDG&E JR proposes to deaverage (referred to as a "capping adjustment" in Exhibit 195, Table IX-2) core commercial rates by 10 percent per year to gradually move all core utility rates closer to their cost of service basis. The SDG&E JR parties further agree to translate this proposal into a fixed revenue amount of $2.291 million per year. This amount reflects the level of dollars transferred each year from core commercial customers, as a group, to residential customers. In D.97-04-082, the Commission adopted core deaveraging as a one-time event. The SDG&E JR proposes to gradually deaverage core rates by 10% per year over three years to mitigate the impact on residential rates.

The Global Settlement credit returns dollars already collected from gas customers on an equal-cents-per-therm basis. This credit account reflects two years of advance collections to pay SDG&E's five-year financial obligation to SoCalGas as specified in the SoCalGas Global Settlement Agreement. The SDG&E JR proposes that the core portion of the credit be returned to core customers through a rate reduction over 24 months and that the noncore, non-former UEG portion be returned to customers in the form of a check or bill credit. The former UEG portion of the credit would be transferred to SDG&E's electric transition cost balancing account (TCBA).

I. CARE and DAP

The SDG&E JR does not propose changing the way SDG&E currently calculates CARE and DAP costs. The existing CARE surcharge is comprised of three components -- CARE program expenses, amortization of the CARE balancing account, and the revenue benefits (i.e., the 15% rate discount provided to participating CARE customers). CARE surcharge costs are recovered from all gas customers, excluding EG customers and participating CARE customers, on an equal-cents-per-therm basis. DAP costs are recovered as a part of SDG&E's base margin costs, and, as such, are allocated to all gas customers on an EPMC basis.

J. Baseline Rates

The SDG&E JR recommends decreasing both the residential baseline and non-baseline rates, and in such a way that reduces the differential between them. Under the SDG&E JR proposal, the non-baseline rate would receive a larger decrease in order to achieve a modest tier closure between the two rates. The SDG&E JR would narrow the difference between the baseline and non-baseline rates from 132% to 128%. Both percentages are measured in terms of the non-baseline as a percent of the baseline rate, and both are measured on a full service basis: i.e., the customer receiving both utility procurement and transportation services.

Narrowing the tier differential in this way provides a 2.9% class decrease and a minimum 1% rate reduction to both the baseline and non-baseline rates, while achieving a modest tier closure between these rates.

K. Master Meter Issues

SDG&E and WMA recommend a fixed unit discount of 31.0 and 23.2 cents per day for customers served under SDG&E's Schedules GT and GS, respectively. Service under Schedules GT or GS is available to master-metered customers in mobile home parks and sub-metered residential units. The parties agree that the use of the rental method of estimating marginal customer costs is appropriate for this purpose. Because we are adopting a settlement we do not approve or disapprove of the allocation method used by the parties.

We note that because this discount is higher than the existing unit discount, the residential rates supported in the SDG&E JR by ORA, SDG&E, and UCAN are slightly impacted. The existing and proposed methods for residential rate design recover this revenue shortfall (caused by providing the space unit discounts) from residential customers only. All other non-residential rates remain the same.

L. Core Commercial and Industrial

The SDG&E JR parties recommend that the Commission adopt a single tariff schedule applicable to all SDG&E's core commercial and industrial (C&I) customers. Doing so would simplify rates and produce lower bills for core C&I customers. The proposed single C&I tariff consists of three tiers of customer charges and three tiers of declining block rates.

SDG&E's core C&I customers are currently served under two tariff schedules: GN-1 for small C&I customers consuming less than 20,800 therms per month (over the past two years or seasons), and GN-2 for all other C&I customers. Both tariff schedules have the same set of charges (i.e., a single service fee and two tiers of declining block rates) but different charge amounts. SDG&E can merge the existing tariffs with minimal changes to the level and structure of the existing charges. And both small and large core C&I customers will see bill decreases, except for small core C&I customers whose consumption is zero.[16]

M. Natural Gas Vehicle (NGV) Rates

The SDG&E JR adopts two NGV proposals originally sponsored by SDG&E. The first proposal seeks to equalize NGV rates among two SDG&E NGV customer groups -- one for buses and military fleets and another for all other vehicles. Although both groups receive identical compressed natural gas services from the utility, they are billed under different rates. The existing rate difference reflects pricing signals for NGV that existed prior to the Commission's issuance of the low emission vehicles (LEV) decision D.95-11-035 (62 CPUC2d

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[16] The current service fee for small core C&I customers is $5 per month. The proposed single tariff fees for this group of customers remain at this level.

395). That decision ordered SDG&E to establish cost-based NGV rates in SDG&E's 1996 BCAP. Since SDG&E's marginal cost calculations do not distinguish between NGV services, a rate difference should not exist. NGV customers should pay the same rate for the same service. If this proposal is adopted, both customer groups will receive double-digit rate decreases.

The second NGV proposal would permit all NGV customers to select transport-only services. Under the existing Schedule G-NGV, SDG&E currently provides four separate NGV services: (a) compressed natural gas service for buses and military fleets; (b) compressed natural gas services for other fleets and vehicles; (c) uncompressed natural gas service for motor vehicles; and (d) natural gas services for co-funded NGV stations. Of these four categories, SDG&E currently provides transport-only services to NGV customers receiving uncompressed gas services under (c). All NGV customers should have the opportunity to participate in transport-only gas services, particularly since these services are currently available to all other (non-NGV) gas customers, both core and noncore. Accordingly, the SDG&E JR makes transport-only gas services available to all NGV customers. This proposal is reasonable and will be adopted.

N. Noncore Rate Design

The SDG&E JR retains the existing rate design for SDG&E's noncore commercial and industrial (noncore C&I) customers. Noncore C&I customers are currently segmented by three service levels -- transmission-only (TLS), high-pressure distribution service (HPS), and medium-pressure distribution service (MPS). Each segmented service has the same rate design consisting of six tiers of customer charges and seasonal volumetric rates, with the winter season lasting four months beginning in December. The SDG&E JR proposes no modifications to this rate design.

The SDG&E JR proposes no changes to the six tiers of customer charges, but recommends a 25% increase (equal to $25), to the automatic meter reading (AMR) charge. In addition, the noncore C&I volumetric rates are revised on an equal percent of revenue basis.[17] This proposal is reasonable and will be adopted.

O. Schedule XGTS

The SDG&E JR proposes that SDG&E eliminate gas services provided under Schedule XGTS. In support of this change, SDG&E says that Schedule XGTS is an experimental tariff that has failed. Schedule XGTS was adopted in SDG&E's 1993 BCAP decision (D.94-12-052, 58 CPUC2d 306) as part of a settlement between SDG&E and DRA (the former ORA). The decision offered experimental Schedule XGTS to introduce the concept of real time pricing (RTP) to gas customers. The SDG&E JR parties advocate terminating the experiment.

SDG&E asserts that Schedule XGTS rate design ensures a revenue shortfall. There are two reasons for this result. First, the off-peak rate under XGTS is set substantially below SDG&E's marginal cost of transmission service, which is approximately one cent per therm.[18] As a result, SDG&E incurs a revenue shortfall for every therm of gas billed under the XGTS off-peak rate.

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[17] While this proposal is not explicit in the SDG&E JR itself, rates that result from Exhibit 195 (Table X-6, column E) confirm a revision of rates computed on an equal percent of revenue basis (i.e., each volumetric rate change is made on the same percent basis).

[18] SDG&E had an off-peak rate of 0.661 cents per therm, which was the current tariff rate under XGTS prior to January 1, 1999. Since that time, SDG&E has revised its rates in compliance with a new cost of service adopted for SDG&E (D.98-12-038) and a revision to SDG&E's unbundled transportation rates, where XGTS is an unbundled transportation tariff, pursuant to CPUC Resolution G-3248, dated February 4, 1999. These revisions have reduced the XGTS off-peak to 0.463 cents per therm.

And, secondly, the frequency of on-peak billing under XGTS has been substantially less than its rate design parameters, resulting in substantially less therms billed at the on-peak rate than anticipated. Billing records reveal that on-peak billing under XGTS occurred only 163 hours over a four and one-half year period, or approximately 1.8 days per year. The rate design parameters for on-peak billing under XGTS assume an annual billing occurrence of approximately 20 days per year. As a result, more therms have been billed under the XGTS off-peak rate than expected, leading to greater revenue shortfalls. These revenue shortfalls will continue to grow if load participation under XGTS is expanded.

Monsanto recommends that SDG&E expand service under XGTS to include EG loads. The SDG&E JR parties oppose this proposal because increasing the load participation under XGTS, without also changing the rate design flaws, will simply result in higher revenue shortfalls. Revenue shortfalls under XGTS receive 100% balancing account treatment, and are allocated to remaining noncore customers. A continuation or expansion of shortfalls under XGTS will simply increase noncore C&I and EG rates and effectively prolong a subsidy of utility services provided to one customer at the expense of all noncore customers.

Even allowing EG customers to take service under XGTS would not achieve the objectives SDG&E originally envisioned. As SDG&E stated, at least 25% of existing EG loads would have to take service under XGTS to achieve a key objective: to entice enough load participation so that future investments in capacity additions could be deferred. Based on the volumes adopted in the SDG&E JR, a 25% EG load participation would equal approximately 162 million therms annually.[19] SDG&E had hoped that the initiation of on-peak price signals under pre-curtailment situations would encourage enough customers, particularly large gas users, to voluntarily reduce their gas use during an on-peak event, and thereby reduce the frequency of, or even the need for, usage mandated gas curtailments.

The only way to achieve the necessary participation level of 162 million therms per year would be to attract either all forecasted cogeneration loads (approximately 51 customers using a total of 169 million therms per year) or a significant portion of former UEG loads to take service under XGTS. The former scenario is not possible since only two or three of SDG&E's largest cogeneration customers have the capability to shift sizeable loads from their business operations on an hourly basis. And, only another two or three of the largest customers would find it cost effective to make the capital investment necessary to shift gas loads on an hourly basis.

The latter scenario is no longer probable, in SDG&E's opinion, because the two large, former UEG customers (i.e., South Bay and Encina power plants) now operate as RMR units. An RMR unit must maintain a certain operational minimum to meet customer electric demand if such demand is not met by the marketplace. As a result, an RMR unit is not likely to take service under XGTS because its RMR obligations could prevent it from reducing loads during an XGTS on-peak price signal event. With high on-peak rates under XGTS, a large

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[19] SDG&E estimated a 25% level of EG participation at 139 million therms per year. This number was based on SDG&E's proposal for an annual forecast of 44 bcf for its former UEG loads. Since the SDG&E JR adopted ORA's annual forecast of 48 bcf for SDG&E's former UEG, the minimum 25% participation level would increase, all other things being equal.

gas user would be unwise to sign up for XGTS if they could not reduce significant loads during a XGTS on-peak price signal event. Currently, the two largest gas users on the SDG&E system, which comprise approximately 40% of system loads on average, are RMR customers and unlikely candidates for XGTS.

Lastly, there is only one customer currently receiving service under XGTS. Consequently, eliminating XGTS will not cause a substantial revenue shift relative to system revenues. The billing revenues received from this customer total approximately $2 million, or less than one percent of total SDG&E system revenues.

We agree with the SDG&E JR and will adopt it with the modification to provide for the Sempra-wide EG rate.

XXI. Comments to the Proposed Decision

The Proposed Decision of the ALJ was issued in accordance with Section 311(d) and Rule 77.1 of the Rules of Practice and Procedure. Comments and reply comments were filed by many parties.[20] Comments merely repeating arguments made in briefs will not be considered.

1. As a result of our review of the Proposed Decision during the comment period we have determined that our approval of the SoCalGas Joint Recommendation must be modified. Our concern with the JR is not with the substantive recommendations on issues. Rather, it is with the implications of the following introductory language of the JR.

> "Unless expressly noted otherwise, it is the intention of the Parties that this Joint Recommendation and sponsoring

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[20] SoCalGas, SDG&E, ORA, TURN, CCC, WATSON, PG&E Generating, SCE, EGA, Vernon, Monsanto, Kern River, CIG/CMA, SCGC, WHP, and Calpine.

> testimony applies for the purposes of this BCAP proceeding only and extends for the full three year BCAP period. It is the intention of the Parties that the Commission should not apply to SoCalGas before December 31, 2002 other cost allocation methodologies, throughput measures, or revenue risk treatment which are inconsistent with the agreement reached in the Joint Recommendation. This provision excludes the potential future unbundling of core interstate pipeline capacity. It is further the intention of the Parties if the core's ten percent ITCS responsibility is reduced in another proceeding, such a modification should not be implemented prior to January 1, 2002. The Parties agree that nothing in this Joint Recommendation and sponsoring testimony may be used as precedent or an admission in any other proceeding or forum; provided that the Parties may introduce the exhibit and sponsoring testimony in a proceeding for the sole purpose of implementing the agreed to resolution of issues as settled in this exhibit." (Emphasis added.)

We cannot approve the underlined language. We cannot permit ORA to be bound from presenting testimony and taking positions in other Commission proceedings which might affect SoCalGas prior to December 31, 2002, in a way inconsistent with the JR. Nor should we bind ourselves in the same way. We are particularly concerned with the possible affect of the JR on our Gas Industry Restructuring investigation I.99-07-003. The JR should not be cause to delay any portion of that OII. Other proceedings involving SoCalGas may arise in the coming years which could impinge on the JR. We do not want to foreclose either ORA's or our ability to act. Further, the Parties should not be foreclosed from assisting the Commission in developing a complete record on other SoCalGas matters.

A recommendation such as the JR has no precedential effect (cf. Rule 51.8). Issues settled in the JR do not foreclose consideration in other proceedings.

Therefore, we adopt the JR but we specifically disapprove of the language underlined above.

2. Pursuant to an agreement between SoCalGas, ORA, and TURN the G-10 and G-20 core commercial and industrial classes have been combined. This has caused a slight revision to the Appendix D Table 1, 2, 3, and 18 in regard to core commercial and industrial rates. No other rate classes are affected.

3. In regard to the RLS tariff the Proposed Decision ordered its termination by December 31, 2002. On reconsideration, we believe that a date in 2002 unnecessarily delays termination. SoCalGas needs only a reasonable opportunity to propose a substitute. In our opinion a date one year from the effective date of this order should be more than adequate.

4. SoCalGas and others believe that the discussions of NCO v. rental methodologies and the replacement cost adder are too extensive and are superfluous in a decision that adopts a joint recommendation on these issues. We disagree. The discussion is not to be considered precedential. It was inserted to show the controversy and the reasonableness of the settlement. We have added some language to the discussion to show more clearly the position of those opposed to ORA and TURN.

5. In regard to the DGN contract SoCalGas has correctly pointed out that the Proposed Decision treated DGN differently than other wholesale customers. To correct this and treat DGN similarly to other wholesale customers, the DGN annualized customer cost, which the Proposed Decision found to be $457,021, is reduced to $22,034.

6. TURN points out that the adopted bundled residential rates in the Proposed Decision have been miscalculated. Commodity costs should be excluded from the calculation and the per-therm value of the customer charge (15.965 cents) should be added to the Tier I volumetric rate. TURN recommends

calculating the differential between the Tier I and Tier II volumetric rates (excluding gas costs) so as to maintain a fixed composite tier differential. We agree and will adopt a 5% composite differential as TURN recommends. Appendix D, Tables 2 and 3 have been modified to correct the tier differential and continue the inverted residential rate structure.

7. SoCalGas, ORA, SCGC, and others continue to recommend segmentation of the EG class at 3,000,000 therms annually. Upon review, we agree with this recommendation and the decision has been modified accordingly.

8. In regard to the Wheeler Ridge cost roll-in, SoCalGas states that to implement the roll-in its Schedule No. G-ITC—Interconnect Access Service should be modified. SoCalGas asserts that since all the costs associated with the Wheeler Ridge facilities have been rolled-in, the firm and interruptible volumetric charges, the zone rate credit, and fuel charge components of the tariff will be eliminated. The single tariff component that will be retained from Schedule No. G-ITC will be the firm access reservation charge. The reservation charge will continue to be charged to SCE and SDG&E based on their daily firm access quantity. This is consistent with the Proposed Decision requirement that these firm access contracts remain in effect and consequently these customers continue to pay for the firm access rights. As SDG&E stated in its Reply Brief (pp. 27-28), in exchange for retaining firm access rights at Wheeler Ridge it is appropriate and acceptable to continue to pay for that firm access.

SoCalGas submits the following Finding of Fact: "Schedule G-ITC should be modified to eliminate the firm and interruptible volumetric charges, the zone rate credit, and fuel charge components of the tariff. The firm access reservation charge will be sole charge component of the tariff that will be retained."

SoCalGas' analysis is correct and its proposed Finding of Fact will be adopted.

9. SoCalGas complains that the Proposed Decision fails to reflect any acknowledgement, acceptance or rejection, of testimony presented by SoCalGas stating that various conditions should be removed from its tariffs that provide cogeneration customers with the right to make service elections after UEG customers have made their elections for service. SoCalGas' reason for removing these conditions is the same as its reason for proposing to remove the CGA from the EG rate, i.e., maintaining preferences for one group (cogeneration) of the EG class customers unfairly discriminates against the other members of the EG class. SoCalGas' testimony supporting the removal of conditions from its tariffs that provide cogeneration customers with the right to make service selections after UEG customers have made their elections for service was not contested. SoCalGas submits the following Finding of Fact: "Special considerations reserved for cogeneration customers during open seasons for transmission and storage service should be removed from SoCalGas' respective storage and transmission service tariffs." SoCalGas' proposal is reasonable and will be adopted.

10. In regard to the DAP cost allocation, TURN points out that in our discussion we said "TURN's proposal is rejected." However, as TURN reminds us, the DAP cost allocation was part of the JR settlement and should not be the subject of a decision on the cost allocation's merits. We modify the decision accordingly.

11. Monsanto complains that the Proposed Decision does not explain why SDG&E's Schedule XGTS has been eliminated. It was eliminated pursuant to the SDG&E JR; but, further, the explanation is simple: The evidence shows that SDG&E incurs a revenue shortfall for every therm of gas billed under the

schedule. Monsanto argues that elimination of the schedule will raise its costs of doing business. We agree.

12. In our review of the Proposed Decision we note that some positions of Long Beach were not discussed. We have briefly discussed Long Beach's position on wholesale rates in section VI.E. Its request to derive wholesale rates based on embedded costs and/or eliminate the LRMC scaler from wholesale rates would require a complete reversal of Commission policy. Long Beach's proposal has previously been rejected, and we see no reason to expand upon our prior discussion rejecting the proposal. (D.94-12-052, 58 CPUC2d 306, 337.)

Additionally, Long Beach requests that this Commission order SoCalGas to sell to Long Beach certain exclusive use facilities at the sales price of about $202,000, the book value of the facilities. SoCalGas has offered to sell the facilities for $1.9 million, which it considers to be its fair market value. Long Beach says that SoCalGas proposes to charge it $301,000 annually to recover the LRMC associated with these exclusive use facilities. (This is a reduction from the current rate of $466,000 annually.) Long Beach does not cite any authority under which we could force a sale at book value. But assuming we had the authority, Long Beach has not presented a persuasive argument for us to do so. SoCalGas has computed the rates charged Long Beach in compliance with Commission decisions. Forcing a sale to save Long Beach $1.7 million benefits no SoCalGas ratepayer, harms SoCalGas, and, we suspect, will not benefit any Long Beach ratepayer. It would be a pure windfall for Long Beach.

Long Beach complains that "since the last BCAP, Long Beach has paid for the exclusive use facilities many times over. Long Beach naturally objects to paying for those facilities over and over again." (Long Beach O.B. p. 15.) Apparently, while waiting for us to force a sale, Long Beach has paid at least $1.7 million in rates. Long Beach's position has no merit.

Findings of Fact

III. SoCalGas Joint Recommendation

1. The recommendations in the Joint Recommendation (Appendix A) are made by SoCalGas, ORA, TURN, CIG/CMA, SDG&E, Chevron, Texaco, and Vernon. These parties represent a broad spectrum of ratepayer interests.

2. The Joint Recommendation recommends certain outcomes in this proceeding related to customer marginal costs, marginal demand costs, core deaveraging, the transmission resource plan, interstate pipeline capacity, the core storage withdrawal reservation, various other storage issues, the direct assistance program, Hub revenues, core and noncore throughput forecasts, noncore revenue risk, the term of this BCAP period, and certain competitive load growth opportunities.

3. The Joint Recommendation was entered into after all direct and rebuttal testimony was reviewed by parties and substantial cross-examination occurred on the issues addressed in the Joint Recommendation.

4. The recommendations in the Joint Recommendation are the result of significant negotiation and compromise of the parties thereto on issues significantly affecting their constituents.

5. The recommendations in the Joint Recommendation, resulting from negotiation and compromise, are recommended as an integrated whole.

6. Each recommendation in the Joint Recommendation is reasonable and in the public interest.

7. The Joint Recommendation is not procedurally flawed, is not contrary to Commission policy, and does not impede transportation or storage competition.

8. The Joint Recommendation is approved, except for the following language in the JR introduction which is disapproved:

It is the intention of the Parties that the Commission should not apply to SoCalGas before December 31, 2002 other cost allocation methodologies, throughput measures, or revenue risk treatment which are inconsistent with the agreement reached in the Joint Recommendation.

9. The parties to the Joint Recommendation recommend the following, as an integrated recommendation:

   a. Implement the ORA position as stated in Exhibit 32 pages 7-2 to 7-3 and adopt the NCO method with the following adjustments:

      1. Adjust the RECC factor as recommended by TURN and consistent with SoCalGas' Exhibit 74 at page 23,

      2. Use TURN's A&G loading factor of 26.12% as shown on TURN's Exhibit 38 page 3-2,

      3. Exclude the replacement cost adder component as recommended by SoCalGas in Exhibit 74 at pages 11-15,

      4. Use SoCalGas' treatment of developer contributions (CIAC) consistent with SoCalGas Exhibit 74 pages 20-21 and revised in Exhibit 111, and

      5. The gas engine total transportation rate will equal SoCalGas' proposed rate ($0.20384 per therm) reflected in the Updated Base Case in Exhibit 107 with the difference allocated to remaining core customers based on equal percent of marginal costs.

   b. Exclude the replacement cost adder methodology from the calculation of marginal demand costs as discussed at SoCalGas Exhibit 74 at pages 11-15.

   c. Adopt TURN's forecast of medium-pressure distribution marginal investment costs of $764.02 per Mcfd of peak day demand as reflected in TURN's Exhibit 38 at pages 3-11 to 3-13.

   d. Adopt TURN's A&G loading factor of 26.12% and TURN's RECC factor consistent with the treatment of customer marginal costs in items a.1 and a.2 above.

e. Adopt TURN's position to deny additional core deaveraging as evidenced in TURN's Exhibit 39 at pages 26-31.

f. Implement a transmission resource plan of $32.5 million that includes the $18 million investment for Line 6900.

g. Adopt ORA's recommendation of a 1044 MMcfd for core interstate capacity reservation as recommended at Exhibit 32 at pages 6-2 to 6-3.

h. Adopt SoCalGas' position that the core retain responsibility for a portion of the ITCS as recommended at Exhibit 11 pages P5 – P6.

i. Adopt SoCalGas' recommendation to not change the allocation of Transwestern TCR surcharges as reflected at Exhibit 72 pages 9-10.

j. Use 1935 MMcfd for core storage withdrawal reservation capacity.

k. Adopt a 50/50 balancing account treatment of unbundled storage revenues. Set the at-risk unbundled storage level at $21 million. The fully scaled marginal cost of unbundled storage would be $31 million. The difference between the fully scaled unbundled noncore storage revenue requirement and the agreed upon $21 million will be charged to the noncore storage balancing account (NSBA). In the event that the NSBA is eliminated, the difference will be recovered through some other mechanism on an equal-cents-per-therm basis. The ratepayer 50% portion will also be recorded to the NSBA. The NSBA balance will be allocated to all customers equal-cents-per-therm. The shareholder 50% share of revenue variances is excluded from the PBR sharing mechanism. Consistent with SoCalGas' proposal at Exhibit 10 pages 0-1 to 0-2, the unbundled noncore storage revenue requirement excludes the Montebello storage field. SoCalGas is given pricing flexibility for all storage products provided the reservation charge will be no higher than 120% of the ceiling reservation charge currently specified in the G-TBS tariff. There will be no changes to the balancing rules as part of the 1999 BCAP.

l. Retain the current allocation method for the direct assistance program costs as evidenced in SoCalGas' Exhibit 74 pages 24-25.

m. Retain the existing HUB revenue treatment as reflected in SoCalGas' Exhibit 77.

n. Adopt the following demand forecasts plus Rosarito demand of 24.9 MMdth.

MMdth	Demand Forecast
Residential	254.7
G-10	78.8
G-20	4.7
Gas Engine	1.6
Gas A/C	0.1
Total Core	339.9
Commercial Industrial	145.7
Electric Generation	294.4
SDG&E	119.7
Long Beach	7.8
Southwest Gas	9.2
Vernon	5.2
DGN	3.6
Total Noncore	585.5
Total Gas Demand	925.4

o. Adopt 75%/25% (ratepayer/shareholder) balancing account for noncore revenues including existing EAD contracts and future contracts as presented at SoCalGas' Exhibit 62 pages 9-11, except (1) non-tariff contracts for service to DGN, (2) future non-tariff contracts with Sempra Energy affiliates not subject to a competitive process, and (3) Competitive Load Growth Opportunities as described in section q. below. The 75%/25% balancing account treatment will apply for throughput purposes. The shareholder 25% share is excluded from the PBR sharing mechanism.

p. Adopt ORA's proposal for a three year BCAP period from January 1, 2000 through December 31, 2002 as presented in Exhibit 31 pages 2-2 to 2-3.

q. Adopt SoCalGas' proposed treatment of Red Team and Rule 38 incentive revenues as presented in Exhibit 15 pages T-32 to T-41.

IV. Length of Periods

10. The BCAP period is the years 2000, 2001, and 2002.

11. The demand forecast for the BCAP period is 950.3 MMdth.

V. Throughput

12. The throughput set forth in the JR of 925.4 MMdth plus Rosarito throughput of 24.9 MMdth (total 950.3 MMdth) is reasonable and adopted.

VI. Long-Run Marginal Costs

13. There is no evidence to support the proposition of Long Beach that the current long run marginal cost methodology should not be used to set wholesale rates.

14. The long run marginal cost methodology used for developing Long Beach's wholesale rate is identical to the long run marginal cost methodology used to set wholesale rates for all other SoCalGas wholesale customers.

15. There is no evidence demonstrating that application of the EPMC scaler to wholesale customers is unfair.

16. There is no evidence upon which the Commission can derive embedded costs for wholesale rates.

17. There is no evidence supporting Long Beach's proposition that exclusive use facilities should be sold by SoCalGas to Long Beach at net book value.

18. Simply because exclusive use facilities have a low book value does not mean that their value is trivial.

19. The load balancing cost allocation for Long Beach as proposed by SoCalGas is reasonable and consistent with that approved by the Commission in SoCalGas' 1996 BCAP proceeding.

20. Long Beach presents no evidence justifying its proposed exemption from the existing SoCalGas load balancing cost allocation methodology.

21. Long Beach provides no evidence demonstrating why average year throughput is a fairer methodology for allocating load balancing costs to wholesale customers than SoCalGas' allocation factor.

22. Long Beach provides insufficient rationale for the Commission to order SoCalGas to enter into a joint rate arrangement with Long Beach to provide gas service to certain customers.

23. There is no evidence to support implementation of a joint rate for a customer in Long Beach.

24. It is reasonable that marketing costs be allocated equally to all five wholesale customers of SoCalGas.

VII. Transmission

25. The JR transmission resource plan of $32.5 million is reasonable and is adopted.

VIII. Electric Generation Schedule

26. On April 1, 1999, the Commission approved Resolution G-3242 authorizing SoCalGas to establish a single customer class for all electricity generators in its service territory and to eliminate the collateral discount rule.

27. Resolution G-3242 ordered elimination of the CGA at the end of the Global Settlement period (August 1, 1999) provided that if the Commission did not adopt a complete proposal to eliminate gaming by August 1, 1999 then the CGA would continue in effect until such safeguards are adopted by the Commission.

28. Resolution G-3242 instructed SoCalGas to address in its 1999 BCAP the issues necessary to prevent gaming.

29. The following exemplary tariff conditions are reasonable for the purpose of eliminating the Commission's gaming concerns and therefore will be adopted. The adoption of these exemplary tariff conditions allow for immediate elimination of the CGA. The tariff conditions are as follows:

a. Subject to paragraph d., the amount of gas to be billed at the electric generation rate for customers having both electric generation and non-electric generation end use on a single meter will be the lesser of a) total metered throughput; or b) a volume equal to the customer's recorded power production in kWh times the average heat rate for their electric generation facilities.

b. The difference between total meter throughput and the volume limitation specified herein will be charged the rate applicable to the other end use served off the meter. When required, as a condition for service under the electric generation rate, electric generation customers will provide the utility with the average heat rate for electric generation equipment as supported by documentation from the manufacturer. If not available, operating data shall be used to determine customers' average heat rate.

c. Electric generation customers receiving electric generation service will make available upon request any measurement devices required to directly or indirectly determine the kilowatt hours generated or the average heat rate for the electric generation equipment. The Utility will have the right to read, inspect and/or test all such measurement devices during normal business hours. Additional gas and/or steam metering facilities required to separately determine gas usage to which the electric generation rate(s) are applicable may be installed, owned and operated by the Utility at its expense in accordance with normal service rules; however, the Utility may, in accordance with No. 2 above utilize estimated data to determine such gas usage.

d. All electric generation customers receiving electric generation service shall be separately metered unless it can be demonstrated that a separate meter is not economically feasible.

30. Special considerations reserved for cogeneration customers during open seasons for transmission and storage service should be removed from SoCalGas' respective storage and transmission service tariffs.

31. Existing regulatory structures have created a mismatch between the pricing of gas and electricity. For gas transportation, the rates of each transporting utility are cumulated — or "pancaked" — so that the ultimate rate the customer sees for gas transportation increases with the number of utility service areas involved in the transport. The price the PX sets for purchases of electricity, by contrast, is uniform throughout the state (or within a zone if congestion occurs) — a "postage stamp" rate.

32. Some California generators pay much higher rates for gas transmission service than others, solely due to their location and the mismatch in regulatory pricing regimes.

33. Competition among electric generators should be based on the efficiency of generating units and the shrewdness of their owners in the gas procurement and financial markets, not on the happenstance of which Sempra affiliate provides local gas service.

34. A Sempra-wide EG rate will benefit electric customers in the form of lower PX prices in some hours, less reliance on RMR units, and lower costs for RMR units when they are called on.

35. The San Diego load center is unusually dependent on imported electricity.

36. The electricity transmission lines that supply San Diego are often subject to physical and technical limitations that can be managed only by operating the few generating plants that are located in SDG&E's territory.

37. The owners of RMR plants receive cost-based payments that are at times higher than PX payments for the same amount of electricity.

38. The Sempra-wide EG rate will lower the cost of gas transportation for the plants served by SDG&E, and will accordingly lower the amount of the payments the ISO makes under the RMR contracts, costs that are borne by all SDG&E electric customers.

39. The Sempra-wide EG rate removes the existing disincentive new generators have against locating in SDG&E's area and existing generators have against expanding or continuing their operations in SDG&E's territory.

40. To the extent that their variable costs — which include the cost of gas transportation — are reduced, SDG&E generators will be able to reduce their bids to the PX.

41. Segmenting the EG class rate between those customers whose annual throughput is less than three million therms and those customers whose annual throughput is more than three million therms is reasonable and is adopted.

42. Segmenting the EG class rate between transmission level and distribution level is not reasonable and is not adopted.

43. It is appropriate that the EG class rate include low emission vehicle (NGV) program costs and RD&D program costs.

IX. ITCS and Interstate Capacity

44. A forecast of the market value of El Paso interstate pipeline capacity from August 1999 through July 2000 of 12.01 cents per MMBtu is reasonable and should be adopted.

45. The methodology SoCalGas used to derive an estimated market value of El Paso interstate pipeline capacity is reasonable.

46. Past or present San Juan basin/California border gas price differentials are unreliable as predictors of the market price of El Paso capacity.

47. SCGC's proposal to establish a market price for brokered capacity based on published indices (in lieu of actual brokered revenues) would create unreasonable risks for SoCalGas.

X. Wheeler Ridge

48. It is reasonable to eliminate the incremental pricing treatment for SoCalGas' Wheeler Ridge interconnect facilities.

49. It is reasonable to roll in the cost of SoCalGas' Wheeler Ridge facilities into SoCalGas' overall transmission rates.

50. Wheeler Ridge has provided, and continues to provide, benefits to all customers of SoCalGas.

51. The total annual revenue requirement related to the Wheeler Ridge facilities to be rolled into rates is $6.83 million per year. This increase, however, will be almost completely offset by the elimination of the zone rate credit.

52. A determination regarding the status of the long term contracts of SCE and SDG&E is not required to resolve Wheeler Ridge issues.

53. Schedule G-ITC should be modified to eliminate the firm and interruptible volumetric charges, the zone rate credit, and fuel charge components of the tariff. The firm access reservation charge will be the sole charge component of the tariff that will be retained.

XI. Storage

54. The recommendations in the JR regarding storage are reasonable and are adopted.

55. A monthly load balancing service allocation of 355 MMcfd is reasonable and is adopted.

56. TURN's recommendation that all available firm injection capacity in excess of 327 MMcfd reserved for the core (121 MMcfd) be allocated to load balancing is unsupported by the evidence.

XII. Other Operating Costs

57. A factor of 1.27% of total annual throughput is reasonable for determining SoCalGas' unaccounted for gas for the BCAP forecast period.

58. A forecast of annual losses from surface leakage, well incidents, and field blow downs of 63 MMcf for the BCAP period is reasonable and is adopted.

59. The carrying costs of gas in storage of $1,702,000 in year 2000, $1,710,000 in year 2001, and $1,710,000 in year 2002 are reasonable and are adopted.

60. Forecasts of transmission fuel at 3,865 MMcf per year, storage fuel at 2,600 MMcf per year, and miscellaneous company use fuel at 355 MMcf per year are reasonable and are adopted.

XIII. System "Windowing" Procedures

61. The issues concerning SoCalGas' operation of its receipt point "windows" are addressed thoroughly in Gas Industry Restructuring and therefore should not be addressed in this BCAP.

62. The issue of whether Hector Road should be established as a normal receipt point is to be addressed in the cost/benefit phase of Gas Industry Restructuring.

63. The issue of whether SoCalGas' receipt point "window" procedures should be tariffed is addressed in the Gas Industry Restructuring proceeding.

XIV. Hub Services

64. The issues SCGC and SCE address related to hub services are being addressed in the Gas Industry Restructuring proceeding and should be resolved in that proceeding.

65. While imbalance penalties incurred by the noncore are credited to the PGA, they are not included in the GCIM.

66. Storage imbalance penalties have no impact on SoCalGas shareholders under the GCIM earnings mechanism.

XV. RLS Tariff

67. The RLS tariff is intended to ensure that SoCalGas' remaining customers will not subsidize a customer who chooses to take service from a bypass pipeline and simply receive peaking service from SoCalGas.

68. It is reasonable to expect that Questar's Southern Trails Pipeline will commence interstate natural gas transportation service in the year 2000 and serve in the Long Beach area ARCO and its affiliate Watson Cogeneration Company, two existing SoCalGas customers.

69. It is reasonable to assume that Kern River's proposed 24-inch pipeline spur off its existing pipeline system into the Long Beach area will begin providing service to existing SoCalGas customers in November, 2001.

70. The RLS tariff was intended to be market based, not cost based. Customers always retain SoCalGas' cost based rate option.

71. There are competitive alternatives to the RLS tariff peaking service market-based rate, such as gas storage, subscribing to additional capacity, burning alternative fuels, altering maintenance schedules, and swapping products in the market.

72. Elimination of the RLS tariff would require a fundamental reevaluation of SoCalGas' volumetric rate design because there are significant differences between FERC tariff rates based upon straight-fixed variable rate design and SoCalGas' existing all-volumetric rates. All volumetric rates put SoCalGas at an inherent disadvantage in a partial bypass situation.

73. Because of the way the RLS tariff increases the otherwise applicable rate, the customers' total cost of gas service will increase as a result of its attempt to cut costs by taking lower-cost partial service from an alternative pipeline.

74. The RLS tariff is applicable to the entire load of all facilities owned by an electric generation customer in SoCalGas' territory, even when only one of the customer's facilities receives partial requirements service.

75. The RLS tariff encourages new generation to locate outside of SoCalGas' service area, and makes it more difficult for existing generation in SoCalGas' territory to compete successfully in the emerging electric markets.

76. SoCalGas forecasts a decline in electric generation throughput from 285.4 MMdth in 1999 to 226.8 MMdth in 2001, a drop of over 20%.

77. SoCalGas forecasts a drop in noncore C&I throughput from 147.0 MMdth in 1999 to 137.1 MMdth in 2001.

78. The RLS tariff increases the cost of electricity generated by plants served by SoCalGas relative to plants out of the service territory or near existing interstate pipelines.

79. PG&E does not have an RLS tariff.

80. Generation projects are being planned throughout PG&E's service territory. New generation in northern California is being sited near centers of population, where it can serve increasing loads and minimize transmission congestion.

81. In the Kern County area, generators are clustering their planned units to take some service from both interstate pipelines and PG&E.

82. Nearly all of the new generation projects serving California are located outside of SoCalGas' service territory, out of state, or along the existing interstate pipeline corridor.

83. Eliminating the RLS tariff would discourage bypass by wire, to the substantial benefit of SoCalGas and its ratepayers.

84. Gas supply competition is critical to the economic survival of both existing and new electric generators (as well as large industrial customers).

85. It is not possible for "pre-bypass load factor" of the customer to exist unless the customer was a full requirements customer of SoCalGas prior to its decision to take a portion of its service from an alternative provider.

86. The current RLS tariff has no mechanism to calculate a pre-bypass load factor for a new customer, or therefore, a ceiling rate in excess of $0.00.

87. The RLS tariff does not apply to new customer load.

88. The RLS tariff should be replaced within one year after the effective date of this decision, with a peaking rate.

89. **Language to this Finding is deleted.**

90. Absent the RLS tariff, the different rate structures offered by SoCalGas and bypassing interstate pipelines would provide an unjustified advantage to customers that partially bypass SoCalGas.

91. SoCalGas should be permitted to propose a revision of its volumetric rate design to provide peak load service.

XVI. Regulatory Balancing Accounts

92. The changes by SoCalGas to its regulatory balancing accounts are reasonable subject to audit.

XVII. Cost Allocation

93. The sum of $396,000 TURN identifies as O&M costs associated with non-metering exclusive use facilities not included in the calculation of marginal customer costs should be included in that calculation.

94. SoCalGas' base margin should be adjusted upon initiation of the new BCAP period to add approximately $2.66 million to SoCalGas' revenue requirement to account for the costs pertaining to transmission lines 325 and 6902.

95. It is reasonable to include as an adjustment to SoCalGas' base margin the sum of $6.83 million to reflect the additional revenue requirement associated with the roll in of the Wheeler Ridge interconnection facility costs.

96. Forecasted throughput for Rosarito should be included in SoCalGas' cost allocation calculation

97. Ultramar's proposal to place a 15 million therm cap on any customer's CARE surcharge is not reasonable and is not adopted.

98. The DGN gas pipeline facilities should be included in marginal customer costs.

XVIII. Rate Design

99. It is reasonable to continue the $5 residential customer charge.

100. It is reasonable to change the summer baseline allowance for climate zones 1, 2, and 3 from 15 therms to 14 therms and the winter baseline allowance for climate zones 1, 2, and 3 from 50 therms, 65 therms, and 87 therms, respectively to 49 therms, 59 therms, and 69 therms, respectively.

101. The foregoing changes to the summer and winter baseline allowances will permit SoCalGas to comply more closely with § 739(d)(1).

102. It is reasonable to segment master meter customers using at least 100 Mth annually from the rest of the master meter class. It is reasonable to treat small master meter customers using less than 100 Mth annually as single family for the purpose of setting a customer charge.

103. For the BCAP period the master meter avoided cost credit shall include scaling and is approximately $.47 per meter per day.

104. It is reasonable to combine the G-10 and G-20 customer classes along with adopting a $10 customer charge for small commercial customers using less than 1,000 therms annually.

105. It is reasonable to segment noncore commercial/industrial customers into distribution and transmission subclasses. Each subclass will have a tariff schedule similar to the G-10 tariff. There will be a single customer charge and a declining block rate schedule.

106. It is reasonable to set the core subscription reservation charges on an all volumetric basis. An all volumetric reservation charge will provide a clear basis for a potential core subscription customer to understand the cost of the capacity associated with the services.

107. For the years 1996 and 1997, the PBOP amounts authorized to be collected by SoCalGas in rates exceeded the actual funding of PBOP liabilities by $8,713,000. It is reasonable for SoCalGas to return these PBOP overcollections to ratepayers by amortizing the balance over a one-year period.

108. SoCalGas' load balancing rules are being addressed comprehensively in Gas Industry Restructuring and are the subject of further investigation in the cost/benefit analysis phase. Therefore, it is not appropriate to resolve issues pertaining to the load balancing rules in this proceeding.

109. The revenue requirement, revenue and cost allocation, and rate changes adopted for SoCalGas are set forth in Appendix D. They are reasonable and are adopted.

XIX. Other Issues

110. The PBOP overcollection shall be amortized over one year.

111. Customer satisfaction issues should be reviewed in SoCalGas' next PBR proceeding.

112. There is no need for any type account to track the effects of QF restructuring on SoCalGas' revenue.

113. Interstate pipeline refunds should be amortized over a period of one year.

XX. SDG&E Issues

114. The Joint Recommendation of the Office of Ratepayer Advocates, San Diego Gas & Electric Company, and Utility Consumers Action Network (SDG&E JR) offers a fair and reasonable resolution of many issues, and is adopted.

115. The SDG&E JR resolves virtually all of the cost allocation issues raised by ORA and UCAN in the SDG&E BCAP.

116. The SDG&E JR's recommendation to extend this BCAP period from two years to three years (January 1, 2000 through December 31, 2002) is reasonable.

117. SDG&E's retail throughput forecast of 718 million therms is reasonable.

118. The SDG&E JR's proposed UEG throughput of 480 million therms is reasonable.

119. The SDG&E JR's cogeneration throughput forecast of 188.9 million therms is reasonable.

120. The marginal costs proposed in the SDG&E JR are reasonable.

121. The SDG&E JR's proposed $31 million resource plan is reasonable.

122. The SDG&E JR's proposed $31 million resource plan only reflects the investments SDG&E identified in its testimony (Exhibit 23) as necessary to serve forecasted load over the 15-year planning horizon.

123. The transmission LRMC must be updated to reflect an additional $7.9 million in proposed international border facilities which should be combined with other SDG&E throughput.

124. The SDG&E JR's recommendation to equalize NGV rates and to expand transport-only services to all NGV customers is reasonable.

125. The SDG&E JR endorses SDG&E's proposal to narrow the tier differential between residential baseline and non-baseline rates by 10% per year, which is reasonable.

126. The SDG&E JR recommends a single tariff schedule for SDG&E's core C&I, which is reasonable.

127. The SDG&E JR recommends retaining the existing rate design for noncore C&I customers, which is reasonable.

128. The SDG&E JR's recommendation to eliminate SDG&E's experimental schedule XGTS is reasonable.

129. The SDG&E JR maintains the status quo for calculating base margin costs.

130. The SDG&E JR allocates a reasonable level of SoCalGas gas transportation costs to SDG&E customers.

131. The SDG&E JR maintains the status quo for calculating marginal cost revenue requirements.

132. The SDG&E JR maintains the status quo for allocating non-base margin costs.

133. The SDG&E JR maintains the existing methodology for calculating CARE and DAP costs for SDG&E.

134. The WMA JR between SDG&E and WMA proposes a reasonable unit discount charge under SDG&E schedules GT and GS, and is adopted.

135. No party objected to SDG&E's proposal to eliminate Schedules GPNC and G-CSTOR. This proposal is reasonable and is adopted.

136. No party objected to the SDG&E's proposal to modify the term of service under Schedule GCORE to a one-year minimum. This proposal is reasonable and is adopted.

137. The revenue requirement, revenue and cost allocation, and rate changes adopted for SDG&E are set forth in Appendix E. They are reasonable and are adopted.

Conclusions of Law

1. A Sempra-wide EG rate complies with Section 454.4. It grants parity to all cogenerators.

2. A cogenerator gas allowance is not needed to comply with Section 454.4.

3. SoCalGas' current method of collecting the CPUC fee from municipal utilities does not violate Section 454.4.

4. The RLS tariff is not in violation of the antitrust laws.

5. The CGA is eliminated.

6. SoCalGas' changes in baseline allowances complies with Section 739(d)(1).

7. The RLS tariff should be replaced within one year after the effective date of this decision with a peaking rate.

8. The revenue requirement, revenue and cost allocations, and rate changes adopted for SoCalGas are reasonable, and are set forth in Appendix D.

9. The revenue requirement, revenue and cost allocations, and rate changes adopted for SDG&E are reasonable, and are set forth in Appendix E.

ORDER

IT IS ORDERED that:

1. Southern California Gas Company (SoCalGas) shall file, no later than 30 days after the effective date of this order, and at least five days prior to their effective date, revised tariff schedules which implement the adopted changes shown in Appendix D. The revised tariff schedules shall comply with General Order (GO) 96-A and shall apply to service rendered on or after their effective date.

2. San Diego Gas & Electric Company (SDG&E) shall file, no later than 30 days after the effective date of this order, and at least five days prior to their effective date, revised tariff schedules which implement the adopted changes shown in Appendix E. The revised tariff schedules shall comply with GO 96-A and shall apply to service rendered on or after their effective date.

3. For customers taking service under the Electric Generator tariff, SoCalGas and SDG&E shall require a separate meter on all facilities used solely for the generation of electricity unless it can be demonstrated that it is not feasible.

4. The Cogenerator Gas Allowances and Collateral Discount Rule are eliminated.

5. SoCalGas shall implement the antigaming tariff provisions set forth in Finding of Fact 29, with the filing of its revised tariff schedules.

6. SoCalGas shall file an application, within 60 days of the effective date of this order, containing a proposed peaking rate to replace the Residual Load Service (RLS) tariff. The RLS tariff shall expire one year from the effective date of this order, or upon approval of a peaking rate, whichever is later.

7. SoCalGas and SDG&E shall jointly file an application, within 60 days after the effective date of this order, proposing a Sempra-wide tariff for EG customers using 3,000,000 therms per year or less, as a class, which caps their rate at the level which prevailed at the EG rate in effect prior to the effective date of this order. Any shortfall in revenue shall be allocated to the >3,000,000 therm class.

8. SoCalGas shall disburse its interstate pipeline refunds in conformity with the refund plan submitted with Exhibit 196.

9. The Office of Ratepayer Advocates shall audit the SoCalGas and SDG&E balancing, tracking, and memorandum accounts for the period beginning January 1, 1996.

10. These two applications are closed.

This order is effective today.

Dated April 20, 2000, at San Francisco, California.

LORETTA M. LYNCH
President
HENRY M. DUQUE
JOSIAH L. NEEPER
CARL W. WOOD
Commissioners

I will file a dissent.

/s/ RICHARD A. BILAS
Commissioner

APPENDIX A

JOINT RECOMMENDATION OF SOCALGAS, ORA, TURN, CIG/CMA SDG&E, CHEVRON, AND TEXACO A.98-10-012

I. INTRODUCTION

The Southern California Gas Company ("SoCalGas"), Office of Ratepayer Advocates ("ORA"), The Utility Reform Network ("TURN"), California Industrial Group/California Manufacturers Association ("CIG/CMA"), San Diego Gas & Electric ("SDG&E"), Chevron U.S.A. Inc. (Chevron), and Texaco Inc. (Texaco) (together the "Parties") have reached agreement on many of the disputed issues in the above referenced case and sponsor this exhibit to enter the terms of their agreement in the evidentiary record for this proceeding.

This Joint Recommendation is a consolidated recommendation in so far as the adoption of any one recommendation is conditioned expressly upon the adoption of all other recommendations. This Joint Recommendation has been entered into by the Parties as the result of numerous negotiations wherein each one of the Parties has, in various instances, agreed to accept an outcome different from its testimony in order to arrive at an acceptable consolidated agreement on issues of importance to each. If any one of the recommendations made in this Joint Recommendation is found unacceptable to the Commission or the Commission can not otherwise adopt this Joint Recommendation in its totality, then the balanced nature of this Joint Recommendation will be breached and it shall no longer stand as the recommendation of the Parties.

Unless expressly noted otherwise, it is the intention of the Parties that this Joint Recommendation and sponsoring testimony applies for the purposes of this BCAP proceeding only and extends for the full three year BCAP period. It is the intention of the Parties that the Commission should not apply to SoCalGas before December 31, 2002 other cost allocation methodologies, throughput measures, or revenue risk treatment which are inconsistent with the agreement reached in the Joint Recommendation. This provision excludes the potential future unbundling of core interstate pipeline capacity. It is further the intention of the Parties if the core's ten percent ITCS responsibility is reduced in another proceeding, such a modification should not be implemented prior to January 1, 2002. The Parties agree that nothing in this Joint Recommendation and sponsoring testimony may be used as precedent or an admission in any other proceeding or forum; provided that the Parties may introduce the exhibit and sponsoring testimony in a proceeding for the sole purpose of implementing the agreed to resolution of issues as settled in this exhibit.

The Parties recognize that the Commission's final adopted decision and authorized tariffs ultimately will govern the cost allocations, rates, service eligibility and charges to be provided by SoCalGas for gas service to all customer classes within the scope of this BCAP.

The Parties agree that each of them have the right to litigate on an independent basis the issues addressed herein in a manner consistent with their testimony in the proceeding. However, it is the Parties expressed preference to have the Commission adopt the recommendations expressed in this Joint Recommendation, and only in the event it does not, do the Parties advocate adoption of their individual positions on the issues.

The witnesses sponsoring this joint recommendation are Johannes Van Lierop for SoCalGas, Mark Pocta for ORA, and Michel Florio for TURN.

II. CUSTOMER MARGINAL COSTS

The Parties agree to stipulate to the ORA position as stated in Exhibit 32 pages 7-2 – 7-3 and adopt the NCO method with the following adjustments:

1. Adjust the RECC factor as recommended by TURN and consistent with SoCalGas' Exhibit 74 at page 23,
2. Use TURN's A&G loading factor of 26.12% as shown at TURN's Exhibit 38 page 3-2,
3. Exclude the replacement cost adder component as recommended by SoCalGas in Exhibit 74 at pages 11-15,

4. Stipulate to SoCalGas' treatment of developer contributions (CIAC) consistent with SoCalGas Exhibit 74 pages 20-21 and revised in Exhibit 111, and

5. The gas engine total transportation rate will equal SoCalGas' proposed rate ($0.20384 per therm) reflected in the Updated Base Case in Exhibit 107 with the difference allocated to remaining core customers based on equal percent of marginal costs.

III. MARGINAL DEMAND COSTS

The Parties agree to exclude the replacement cost adder methodology from the calculation of marginal demand costs as discussed at SoCalGas Exhibit 74 at pages 11-15.

The Parties agree to adopt TURN's forecast of medium-pressure distribution marginal investment costs of $764.02 per mcfd of peak day demand as reflected at TURN's Exhibit 38 at pages 3-11 – 3-13.

The Parties stipulate to TURN's A&G loading factor of 26.12% and TURN's RECC factor consistent with the treatment of customer marginal costs above.

IV. CORE DEAVERAGING

The Parties stipulate to TURN's position to deny additional core deaveraging as evidenced in TURN's Exhibit 39 at pages 26-31.

V. TRANSMISSION RESOURCE PLAN

The Parties agree to a compromised transmission resource plan of $32.5 million which is the half-way point between the proposed SoCalGas transmission resource plan of $18 million as proposed in Exhibit 9 pages N-3 – N-8 and TURN's transmission resource plan of $47 million as proposed in Exhibit 39 at pages 17-20. The $32.5 million transmission resource plan includes the $18 million investment for Line 6900 and assigns a 50% probability to the necessity for the $29 million Adelanto project.

VI. INTERSTATE PIPELINE CAPACITY

The Parties agree to stipulate to ORA's recommendation of a 1044 mmcfd for core interstate capacity reservation as recommended at Exhibit 32 at pages 6-2 – 6-3.

The Parties agree to stipulate to SoCalGas' position that the core retain responsibility for a portion of the ITCS as recommended at Exhibit 11 pages P5 – P6.

The Parties stipulate to SoCalGas' recommendation to not change the allocation of Transwestern TCR surcharges as reflected at Exhibit 72 pages 9-10.

VII. CORE STORAGE WITHDRAWAL RESERVATION

The Parties agree to a compromise of 1935 mmcfd for core storage withdrawal reservation capacity. This represents a midpoint between the SoCalGas proposal of 2082 mmcfd at Exhibit 10 page O-4 – O-5 and TURN's recommendation of 1782 mmcfd at Exhibit 39 pages 10-15.

VIII. ALL OTHER STORAGE ISSUES

The Parties agree to 50/50 balancing account treatment of unbundled storage revenues. The Parties also agree to set the at-risk unbundled storage level at $21 million. Because of the impact of the marginal cost changes resulting from the Joint Recommendation the fully scaled marginal cost of unbundled storage would be approximately $31 million. The difference between the fully scaled unbundled noncore storage revenue requirement and the agreed upon $21 million will be charged to the noncore storage balancing account (NSBA). In the event that the NSBA is eliminated, it is the intent of the Parties that the difference will be recovered through some other mechanism on an equal cents per therm basis. The ratepayers 50% portion will also be recorded to the NSBA. The NSBA balance will be allocated to all customers equal cents per therm. The shareholder 50% share of revenue variances is excluded from the PBR sharing mechanism. Consistent with SoCalGas' proposal at Exhibit 10 pages O-1 – O-2, the unbundled noncore storage revenue requirement excludes the Montebello storage field even if the field is not sold prior to effective date of the 1999 BCAP. The Parties also agree to grant SoCalGas pricing flexibility for all storage products provided the reservation charge will be no higher than 120% of the ceiling reservation charge currently specified in the G-TBS tariff. There will be no changes to the balancing rules as part of the 1999 BCAP.

The Parties agree that the treatment of the NSBA (ratepayer/shareholder risk sharing, marginal cost, revenue requirement, etc.) and other storage cost issues will be subject to reconsideration in the Gas OIR if significant changes to storage operations or balancing rules are proposed in that proceeding.

IX. DIRECT ASSISTANCE PROGRAM

The Parties agree to retain the current allocation method for the direct assistance program costs as evidenced in SoCalGas' Exhibit 74 pages 24-25.

X. HUB REVENUES

The Parties agree to retain the existing HUB revenue treatment as reflected in SoCalGas' Exhibit 77.

XI. THROUGHPUT

The Parties stipulate to SoCalGas' proposed core throughput. The residential throughout forecast is reflected at Exhibit 2 page G-2 and nonresidential core demand forecast is reflected at Exhibit 3 pages H-2 – H-6.

The Parties agree to compromise between the SoCalGas and ORA noncore demand forecast to 585.2 mmdth (excludes Enhanced Oil Recovery and International Border Service Tariff throughput). This compromise is 13.5 mmdth higher than the noncore demand forecast presented in SoCalGas' prepared direct testimony (Exhibits 4,6&7). Additional noncore throughput of 10.1 mmdth and 3.4 mmdth are assigned to the SoCalGas and SDG&E electric generation (EG) load, respectively. The compromise results in the SoCalGas EG and SDG&E wholesale demands to increase to 295.5 mmdth and 119.7 mmdth, respectively. A summary of the Joint Recommendation throughput forecast is below.

MMdth	Joint Recommendation Demand Forecast
Residential	254.7
G-10	79.1
G-20	4.7
Gas Engine	1.6
Gas A/C	0.1
Total Core	340.2
Commercial/Industrial	147.0
Electric Generation	295.5
SDG&E	119.7
Long Beach	7.8
Southwest Gas	9.2
Vernon	2.5
DGN	3.6
Total Noncore	585.2
Total Gas Demand	925.4

XII. NONCORE REVENUE RISK

Parties stipulate to 75%/25% (ratepayer/shareholder) balancing account for noncore revenues including existing EAD contracts and future contracts as presented at SoCalGas' Exhibit 62 pages 9-11, except (1) non-tariff contracts for service to DGN, (2) future non-tariff contracts with Sempra Energy affiliates not subject to a competitive process, and (3) Competitive Load Growth Opportunities as described in section XIV below.

A competitive process shall, at a minimum, include an intrastate transportation service proposal offered by SoCalGas to all similarly situated market participants on a non-discriminatory basis. Whether the contract award met the competitive process standard will be determined on a case-by-case basis. If SoCalGas' revenue credit cost allocation proposal for treatment of the international border service tariff revenues is not adopted but rather, the Commission approves regular tariff and cost allocation treatment like other noncore classes except EOR, the 75%/25% balancing account treatment will apply for throughput purposes. The shareholder 25% share is excluded from the PBR sharing mechanism.

XIII. BCAP PERIOD

The parties agree to ORA's proposal for a three year BCAP period from January 1, 2000 through December 31, 2002 as presented at Exhibit 32 pages 2-2 – 2-3.

XIV. COMPETITIVE LOAD GROWTH OPPORTUNITIES

The Parties agree to accept SoCalGas' proposed treatment of Red Team and Rule 38 incentive revenues as presented in Exhibit 15 pages T-32 – T-41.

Addendum to Exhibit 169

Joint Recommendation of SoCalGas, ORA, TURN, CIG/CMA, SDG&E, Chevron, Texaco, and Vernon

The City of Vernon has agreed to join the Joint Recommendation. The Joint Recommendation now includes SoCalGas, ORA, TURN, CIG/CMA, SDG&E, Chevron, Texaco, and the City of Vernon (the "Parties"). The Joint Recommendation was introduced into the 1999 SoCalGas BCAP record (A.98-10-012) as Exhibit 169. The Parties agree to the terms and conditions set forth in Exhibit 169 with the following revisions:

1. The Parties agree to a load balancing cost allocation for the City of Vernon that is based on an equal cents per therm rate based on the average load balancing costs of the other wholesale customers.
2. The City of Vernon throughput is increased to 5,162 MDth per year to reflect the migration to Vernon wholesale service during the BCAP period. As a result, the core commercial and industrial, noncore commercial and industrial, and electric generation throughput is decreased slightly to prevent double counting. The revised throughput is reflected in the following table:

MMdth	Joint Recommendation Demand Forecast (revised)
Residential	254.7
G-10	78.8
G-20	4.7
Gas Engine	1.6
Gas A/C	0.1
Total Core	339.9
Commercial/Industrial	145.7
Electric Generation	294.4
SDG&E	119.7
Long Beach	7.8
Southwest Gas	9.2
Vernon	5.2
DGN	3.6
Total Noncore	585.5
Total Gas Demand	925.4

The resulting impact of the above changes to the Joint Recommendation are reflected in the attached updated cost allocation ("C" tables) and rate design ("D" tables) tables.

(END OF APPENDIX A)

APPENDIX B

D 00-04-060

Before the Public Utilities Commission
of the State of California

Application of SAN DIEGO GAS & ELECTRIC COMPANY for Authority, Among Other Things, To Change Its Rates And Charges For Gas Service.	))))	Application No. 98-10-031

BIENNIAL COST ALLOCATION PROCEEDING

Joint Recommendation on Master Meter Differential Issues

The Western Mobilehome Parkowners Association (WMA) and San Diego Gas and Electric Company(SDG&E) jointly recommend the following on Issue 12.b, Master Meter discount issues in the San Diego BCAP:

1) In the master meter differential methodology for mobilehome park customers, the use of the rental cost method is recommended for estimating utility marginal customer costs for the purpose of establishing utility avoided costs.

2) The parties agree that for purposes of the Commission's decision in the SDG&E BCAP proceeding, the master meter differential for mobilehome park customers will be based on unscaled marginal customer costs as calculated by Dr. McCann in Exhibit 156, Table WMA-1 (SDG&E BCAP).

3) The issue of scaling marginal costs to embedded costs for SDG&E will be deferred to a future proceeding.

4) The master meter discount for mobilehome park customers of San Diego Gas and Electric will be thirty six cents ($0.36) per space per day or thirty one cents ($0.31) per space per day, depending on resolution of the service line marginal cost issues in A. 98-10-031 and pending resolution of the scalar issue in any future proceeding.

WILLIAM JULIAN II for
WESTERN MOBILEHOME ASSOCIATION

S/ by WJII

VICKI L. THOMPSON for
SAN DIEGO GAS AND ELECTRIC COMPANY

(END OF APPENDIX C)

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company (U902-G) for Authority to Revise its Rate Effective August 1, 1999, in its Biennial Cost Allocation Proceeding	)))))	Application 98-10-031 (Filed October 15, 1998)

JOINT RECOMMENDATION OF THE OFFICE OF RATEPAYER ADVOCATES, SAN DIEGO GAS & ELECTRIC COMPANY, AND UTILITY CONSUMERS ACTION NETWORK

I. INTRODUCTION

The Office of Ratepayer Advocates (ORA), San Diego Gas & Electric Company (SDG&E) and the Utility Consumers Action Network (UCAN) (collectively, the Parties) offer this joint recommendation on many of the disputed issues in SDG&E's 1999 Biennial Cost Allocation Proceeding (BCAP) (A. 98-10-031). As will be discussed below, the Parties believe that this agreement as a whole, offers a fair and reasonable result in light of the entire evidentiary record.

II. BACKGROUND

SDG&E filed its 1999 BCAP application on October 15, 1998. By ALJ Ruling, dated October 30,1998, the SDG&E application was consolidated with the 1999 Southern California Gas Company (SoCalGas) BCAP application (A. 98-10-012) and the joint SDG&E/SoCalGas application for approval of a gas transmission service tariff to the Rosarito power plant in Mexico (A. 98-07-005).

Because of the large number of parties and issues in this case, the adopted procedural schedule established "staggered" deadlines for parties wishing to present testimony concerning the three applications. ORA and other interested parties served prepared testimony regarding the SDG&E BCAP in March. Parties served rebuttal testimony in April, followed by approximately four-weeks of evidentiary hearings.

Throughout this lengthy process which included many months of extensive discovery, the Parties recognized that it was possible to reach consensus on several contested issues. To that end, the Parties held several discussions in an attempt to reach an agreement that is fair, reasonable and in the public interest. This Joint Recommendation is the product of the Parties successful efforts.

III. THE AGREEMENT

The Joint Recommendation below offers fair and reasonable resolutions to virtually all of the issues that have been disputed in the SDG&E 1999 BCAP:

A. Marginal Cost and Cost Allocation

Customer Marginal Costs:

The Parties agree to stipulate to the ORA and UCAN position and adopt NCO Method as stated in Exhibit 33 at pg. 4-2 through 4-4, with the following adjustments:

Residential:

- Stipulate to UCAN's per unit marginal customer costs as set forth in Exhibit 41 at Attachment E at pg. E-1.

Non-Residential:

- Stipulate to ORA's Service Line, Regulator, and Meter ("SRM") new capital costs as set forth in Exhibit 33 at pg. 4-4, Section 4.2.2 (a).
- Stipulate to ORA's SRM replacement capital cost calculations as set forth in Exhibit 33 at pg. 4-5, Section 4.2.2. (b).
- Stipulate to UCAN's reduction of SDG&E's variable customer costs (for returned check and field collection charges, and service establishment fees) as set forth in Exhibit 41 at pg. 10.
- Adopt UCAN's A&G loader of 13.995% from Exhibit 41 at pg. 1.

Marginal Demand Costs:

- The Parties agree to adopt ORA's medium pressure (MPS) and high pressure (HPS) capital related distribution marginal cost calculations (including Zero Intercept Regression) from Exhibit 33 at. Pgs. 4-8 through 4-10.
- Stipulate to SDG&E position found in Exhibit 133 at pgs. 4 through 5, to deny replacement cost adder methodology.
- Adopt UCAN's A&G loader of 13.995% found in Exhibit 41 at pg. 1.

Transmission Resource Plan:

- The Parties agree to a $31.0 million transmission resource plan (excluding International Border facilities) which is a compromise between the plans found in Exhibit 23 at pg. VII-1 and in Exhibit 33 at pgs. 3-1, 3-12.

Core Deaveraging:

The Parties agree to continue modest core deaveraging: Stipulate to ORA proposal for annual deaveraging, set to a specific percentage of 10% per year as set forth in Exhibit 33 at pg. 5-11.

B. Throughput and Revenue Issues

Throughput Forecast:

The Parties agree to stipulate to SDG&E proposed levels of throughput for residential, commercial, and industrial/cogeneration from Exhibit 18 at pg. II-1. Adopt ORA's EG throughput level of 480 million therms/year found in Exhibit 33 at pg. 2-1.

BCAP Period:

Stipulate to ORA position: 3 years, January 1, 2000 through December 31, 2002 from Exhibit 33 at pg. 1-2.

EG Rate Proposal:

The Parties agree to a two-tiered volumetric rate design as offered by SDG&E in its Rebuttal Testimony. The EG rates would be as follows (exemplary, based on the SoCalGas Joint Recommendation and SDG&E Joint Recommendation proposals):

	Part A	Part B
Customer Charges, $ per month	$20	$2,326
Tier 1, cents per therm	9.009	8.490
Tier 2, cents per therm	8.075	5.162

Part A rates would apply to EG customers whose usage is less than 1 million therms per month, and the Tier 1 charges would apply to the first 21,000 therms per month. Part B charges would apply to EG customers whose usage is equal to or exceeds 1 million therms per month, and the Tier 1 charges would apply to the first 1 million therms per month. The final EG rates would be calculated by incorporating any changes of inputs that result from the BCAP decision into SDG&E's rate design spreadsheet (EG Option 4b2).

Tariff Proposals:

The Parties agree to eliminate the XGTS tariff as proposed in Exhibit 26 at Revised pg. XI-11 and in Exhibit 33 at pg. 5-13.

Adopt SDG&E's proposals for NGV rate changes as found in Exhibit 26 at Revised Pg. X-5.

GTNC Customer Charges:

The Parties stipulate to ORA position for no changes to GTNC customer charges as set forth in Exhibit 33 at pg. 5-12.

Lost and Unaccounted For Gas (LUAF):

The Parties stipulate to the corrected LUAF calculations as set forth in Exhibit 117 at Attachment A.

Global Prepayment:

The Parties agree to:

Core: Stipulate to ORA position to return the entire core amount of Global Prepayment to core customers in rates over 24 months at Exhibit 33 at pg. 5-10.

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- Checks or bill credits to noncore customers (customer option).
- Return to UEG via transfer to TCBA.

Balancing Accounts:

The Parties agree that the balancing accounts will also be adjusted and updated prior to establishing final BCAP rates.

C. Interaction with PBR Indexing D.99-05-030

1999 Gas Base Rate Revenue Requirement of $201.5 million adopted in D. 98-12-038 will be spread utilizing the sales forecast reflected in this BCAP Joint Recommendation. Cost Allocation and Rate Design settled upon in this Joint Recommendation will be used to adjust gas cost allocations and rates immediately prior to implementing the PBR rate indexing methodology adopted in D.99-05-030 for setting the January 1, 2000 rates.

IV. GENERAL TERMS

Parties should note that issues not expressly addressed herein are not included in this Joint Recommendation, and on those matters, parties are free to advocate their individual proposals. For example, the Joint Recommendation does not address (1) whether the EG rate should be regional and, if so, the specific regional rate; or (2) issues related to Rosarito/USGen rates and Schedule IB tariff.

The Joint Recommendation is viewed as a whole --that is each recommendation is expressly conditioned upon Commission acceptance of all other recommendations. Parties to this Joint Recommendation fully and without exception support the adoption of this Joint Recommendation in its entirety. No Party to this Joint Recommendation will contest any aspect of this Joint Recommendation in this proceeding or any other forum, by contact or communication, whether written or oral (including ex parte communications whether or not reportable under the Commission's Rules) or in any manner before this Commission.

The Parties further agree that they will not enter into any ex parte discussions with any Commission decision maker regarding the recommendations contained in this Joint Recommendation, whether reportable under the Commission's Rules or not, except in the presence of the other Parties hereto or unless otherwise agreed to by all the Parties.

Endorsement of this Joint Recommendation shall not be construed to be an acceptance or ratification of the principles, assumptions, methodologies, positions, or arguments underlying the recommendations contained herein.

The Parties intend that this Joint Recommendation is subject to each and every condition set forth herein, including its acceptance by the Commission in its entirety and without change or condition. Unless the Commission accepts the Parties' recommendations contained herein in their entirety, without change or condition, this Joint Recommendation shall be null and void, unless otherwise agreed upon by the Parties.

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/ (END OF APPENDIX B)

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D00-04-060

APPENDIX B

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company (U902-G) for Authority to Revise its Rate Effective August 1, 1999, in its Biennial Cost Allocation Proceeding	)))))	**Application 98-10-031** **(Filed October 15, 1998)**

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/ (END OF APPENDIX B)

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APPENDIX C

D 00-04-060

Before the Public Utilities Commission
of the State of California

Application of SAN DIEGO GAS & ELECTRIC COMPANY for Authority, Among Other Things, To Change Its Rates And Charges For Gas Service.)	Application No. 98-10-031

BIENNIAL COST ALLOCATION PROCEEDING

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William Julian II

WILLIAM JULIAN II for
WESTERN MOBILEHOME ASSOCIATION

S/ by WJII

VICKI L. THOMPSON for
SAN DIEGO GAS AND ELECTRIC
COMPANY

(END OF APPENDIX C)

APPENDIX D

TABLE 1

SUMMARY OF TRANSPORTATION REVENUE CHANGES

SOUTHERN CALIFORNIA GAS COMPANY

2000 Biennial Cost Allocation Proceeding

	BCAP REVENUES AT RATES IN EFFECT 1/01/2000 (M$)	REVENUES AT BCAP AUTHORIZED RATES (M$)	INCREASE (DECREASE) (M$)	CHANGE (%)
	(A)	(B)	(C=B-A)	(D=C/A)
CORE PROCUREMENT:				
RESIDENTIAL	1,133,893	1,019,745	(114,148)	(10.067)
LARGE MASTER METERED	11,655	11,220	(435)	(3.734)
CORE COMMERCIAL & INDUSTRIAL	228,544	191,359	(37,186)	(16.271)
GAS A/C	155	119	(36)	(23.064)
GAS ENGINE	2,495	3,150	655	26.243
TOTAL CORE PROCUREMENT	1,376,743	1,225,593	(151,150)	(10.979)
CORE TRANSPORTATION:				
RESIDENTIAL	11,383	10,229	(1,154)	(10.134)
LARGE MASTER METERED	117	112	(4)	(3.775)
CORE COMMERCIAL & INDUSTRIAL	41,111	34,500	(6,612)	(16.082)
GAS A/C	20	15	(5)	(23.532)
GAS ENGINE	129	163	34	26.708
TOTAL CORE TRANSPORTATION	52,759	45,020	(7,740)	(14.670)
TOTAL CORE	1,429,502	1,270,613	(158,890)	(11.115)
NONCORE:				
COMMERCIAL & INDUSTRIAL	90,005	79,360	(10,645)	(11.827)
ELECTRIC GENERATION	121,041	99,785	(21,256)	(17.561)
NONCORE SUBTOTAL	211,046	179,144	(31,901)	(15.116)
WHOLESALE				
LONG BEACH	3,545	2,295	(1,250)	(35.264)
SAN DIEGO GAS & ELECTRIC	51,147	32,347	(18,800)	(36.757)
SOUTHWEST	3,563	2,531	(1,032)	(28.971)
VERNON	N/A	1,288	1,288	N/A
TOTAL WHOLESALE	58,255	38,461	(19,795)	(33.979)
INTERNATIONAL				
DGN	N/A	974	974	N/A
UNBUNDLED STORAGE	27,979	21,000	(6,979)	(24.944)
UNALLOCATED COSTS TO NSBA (per J.R.)		11,187	11,187	N/A
NET CARE REVENUES	879	2,050	1,171	133.256
SYSTEM TOTAL	1,727,662	1,523,429	(204,233)	(11.821)
TOTAL CARE REVENUES	33,281	5,574	(27,707)	(83.253)
EOR REVENUES	32,616	22,777	(9,839)	(30.166)

TABLE 2

CORE PROCUREMENT CUSTOMER: TRANSPORTATION RATES
SOUTHERN CALIFORNIA GAS COMPANY

2000 Biennial Cost Allocation Proceeding

Core Customer Class	Throughput (Mth) or # of Customers	Rates in Effect [2] 1/01/2000 Rate ($/th)	Revenue ($M)	BCAP Authorized Rates Rate ($/th)	Revenue ($M)
(A)	(B)	(C)	(D)	(E)	(F)
RESIDENTIAL					
Customer Charge					
Single Family	3,060,513			$5.00	183,631
Multi-Family Family	1,470,953			$5.00	88,257
Small Master Metered	117,058			$5.00	7,023
Submeter Credit					(16,255)
Tier I Volumetric	1,645,168			0.24405	401,506
Tier II Volumetric	838,856			0.42389	355,583
Subtotal Residential	2,484,024	0.45647	1,133,893	0.41052	1,019,745
LARGE MASTER METERED					
Customer Charge	181			$161.32	351
Tier I Volumetric	25,501			0.26214	6,685
Tier II Volumetric	11,859			0.35289	4,185
Subtotal Residential	37,360	0.31198	11,655	0.30033	11,220
CORE COMMERCIAL & INDUSTRIAL		**Small (G-10)**		**Combined (G-10/G-20)**	
Customer Charge	170,706	$15.00	30,727	$10.00/15.00	26,542
Tier I Volumetric [1]	136,872	0.50960	69,749	0.38280	52,473
Tier II Volumetric	427,241	0.26313	112,418	0.22955	99,283
Tier III Volumetric	106,990	0.10908	11,670	0.10006	13,061
Subtotal G-10	671,103	0.33462	224,565	0.27333	191,359
LARGE CORE COMMERCIAL & INDUSTRIAL (G-20)					
Customer Charge	59	$350.00	247.04	NA	NA
Tier I Volumetric [3]	5,474	0.21290	1,165	NA	NA
Tier II Volumetric	23,536	0.10908	2,567	NA	NA
Subtotal G-20	29,010	0.13718	3,980	NA	NA
NON-RES GAS A/C					
Customer Charge		$150.00	29	$150.00	29
Volumetric	1,060	0.11924	126	0.08551	91
Subtotal Non-Res Gas A/C	1,060	0.14624	155	0.11251	119
GAS ENGINES					
Customer Charge		$50.00	398	$50.00	398
Volumetric	15,240	0.13761	2,097	0.18057	2,752
Subtotal Gas Engines	15,240	0.16371	2,495	0.20668	3,150

[1] Tier I quantity equals first 250 therms per month in December - March, and first 100 therms per month in April - November.
Tier II quantity is from Tier I to 4,167 therms. The customer charge is $10 for customers < 1000 therms/year & $15 for all other customers.

[2] 1/01/2000 rates for residential and core commercial & industrial are based on proposed total number of customers, proposed demand forecasts, D.97-04-082 residential baseline-Tier II factors and present rates for both residential and both small & large core commercial & industrial.

[3] Tier 1 quantity is first 4167 therms.

NOTE: Bundled Procurement Transportation Rates rates exclude a brokerage fee of 0.201 cents/therm, and the Core Portfolio WACOG. The current core WACOG including brokerage fee is 17.602 ¢/therm. The core WACOG is updated monthly, and along with the brokerage fee is additive to all bundled Procurement Transportation Rates.

TABLE 3

CORE TRANSPORTATION CUSTOMER: TRANSPORTATION RATES

SOUTHERN CALIFORNIA GAS COMPANY

2000 Biennial Cost Allocation Proceeding

Core Customer Class	Throughput (Mth) or # of Customers	Rates in Effect [2] 1/01/2000 Rate ($/th)	Revenue ($M)	BCAP Authorized Rates Rate ($/th)	Revenue ($M)
(A)	(B)	(C)	(D)	(E)	(F)
RESIDENTIAL					
Customer Charge					
Single Family	30,914			$5.00	1,855
Multi-Family Family	14,858			$5.00	891
Small Master Metered	1,182			$5.00	71
Submeter Credit					(164)
Tier I Volumetric	16,618			0.24121	4,008
Tier II Volumetric	8,473			0.42105	3,568
Subtotal Residential	25,091	0.45365	11,383	0.40768	10,229
LARGE MASTER METERED					
Customer Charge	2			$161.32	4
Tier I Volumetric	258			0.25930	67
Tier II Volumetric	120			0.35005	42
Subtotal Residential	377	0.30916	117	0.29749	112
CORE COMMERCIAL & INDUSTRIAL		Small (G-10)		Combined (G-10/G-20)	
Customer Charge	29,679	$15.00	5,342	$10.00/15.00	4,619
Tier I Volumetric [1]	23,796	0.50678	12,059	0.37996	9,090
Tier II Volumetric	74,279	0.26031	19,335	0.22671	17,575
Tier III Volumetric	18,601	0.10626	1,976	0.09723	3,216
Subtotal G-10	116,677	0.33180	38,713	0.25646	34,500
LARGE CORE COMMERCIAL & INDUSTRIAL (G-20)					
Customer Charge	36	$350.00	152	NA	NA
Tier I Volumetric [3]	3,367	0.21008	707	NA	NA
Tier II Volumetric	14,478	0.10626	1,538	NA	NA
Subtotal G-20	17,845	0.13436	2,398	NA	NA
NON-RES GAS A/C					
Customer Charge		$150.00	4	$150.00	4
Volumetric	140	0.11642	16	0.08267	12
Subtotal Non-Res Gas A/C	140	0.14342	20	0.10967	15
GAS ENGINES					
Customer Charge		$50.00	21	$50.00	21
Volumetric	800	0.13479	108	0.17773	142
Subtotal Gas Engines	800	0.16090	129	0.20384	163
TOTAL CORE CARE SURCHARGE	3,157,285	0.00721	22,774	0.00121	3,814

[1] Tier I quantity equals first 250 therms per month in December - March, and first 100 therms per month in April - November.
Tier II quantity is from Tier I to 4,167 therms. The customer charge is $10 for customers < 1000 therms/year & $15 for all other customers.

[2] 1/01/2000 rates for residential and core commercial & industrial are based on proposed total number of customers, proposed demand forecasts, D.97-04-082 residential baseline-Tier II factors and present rates for both residential and both small & large core commercial & industrial.

[3] Tier 1 quantity is first 4167 therms.

TABLE 4

NONCORE TRANSPORTATION RATES

SOUTHERN CALIFORNIA GAS COMPANY

2000 Biennial Cost Allocation Proceeding

Noncore Customer Class	Throughput (Mth)	Rates in Effect 1/01/2000 Rate ($/th)	Rates in Effect 1/01/2000 Revenue ($M)	BCAP Authorized Rates Rate ($/th)	BCAP Authorized Rates Revenue ($M)
(A)	(B)	(C)	(D)	(F)	(G)
NONCORE					
COMMERCIAL & INDUSTRIAL					
VOLUMETRIC RATE	1,456,757	0.04651	67,757	0.04655	67,809 [2]
ITCS	1,456,757	0.01527	22,248	0.00793	11,551
TOTAL	1,456,757	0.06178	90,005	0.05448	79,360
CARE SURCHARGE	1,456,757	0.00721	10,508	0.00121	1,760
ELECTRIC GENERATION (EG) [1]					
VOLUMETRIC RATE	2,944,257	0.02584	76,076	0.02291	67,464 [3]
ITCS	2,944,257	0.01527	44,965	0.00793	23,345
SUBTOTAL	2,944,257	0.04111	121,041	0.03084	90,809
COMMON EG RATE ADJ.	2,944,257			0.00305	8,976
TOTAL	2,944,257			0.03389	99,785
WHOLESALE					
LONG BEACH					
VOLUMETRIC RATE	77,821	0.03036	2,363	0.02160	1,681
ITCS	77,821	0.01520	1,183	0.00789	614
TOTAL	77,821	0.04556	3,545	0.02949	2,295
SDG&E					
VOLUMETRIC RATE	1,445,680	0.02018	29,176	0.01448	20,940
ITCS	1,445,680	0.01520	21,971	0.00789	11,407
TOTAL	1,445,680	0.03538	51,147	0.02237	32,347
SOUTHWEST GAS					
VOLUMETRIC RATE	91,672	0.02367	2,170	0.01972	1,808
ITCS	91,672	0.01520	1,393	0.00789	723
TOTAL	91,672	0.03887	3,563	0.02761	2,531
VERNON					
VOLUMETRIC RATE	51,620	N/A	N/A	0.01706	881
ITCS	51,620	N/A	N/A	0.00789	407
TOTAL	51,620	N/A	N/A	0.02495	1,288
INTERNATIONAL					
DGN					
VOLUMETRIC RATE	36,419	N/A	N/A	0.01886	687
ITCS	36,419	N/A	N/A	0.00789	287
VOLUMETRIC RATE	36,419	N/A	N/A	0.02675	974
BROKERAGE FEES	31,326	0.00266	83	0.00266	83

[1] Includes all electric generation including traditional Utility Electric Generation Municipal and all Qualifying Facilities.

[2] See Table 5 for BCAP adopted noncore commercial and industrial segmented rate design.

[3] See Table 8 for BCAP adopted EG segmented rate design.

TABLE 5

NONCORE COMMERCIAL & INDUSTRIAL RATES

SOUTHERN CALIFORNIA GAS COMPANY
2000 Biennial Cost Allocation Proceeding

	Throughput (Mth) or # of Customers	Rates in Effect 1/01/2000 Rate ($/th)	Rates in Effect 1/01/2000 Revenues (M$)	BCAP Authorized Rates Rate ($/th)	BCAP Authorized Rates Revenues (M$)
DISTRIBUTION SERVICE					
Customer Charge	1,140	Varied	10,312	$350.00	4,788
Volumetric Rates					
Tier 1 0 - 250,000	236,030			0.10091	23,817
Tier 2 250,000 - 1,000,000	312,418			0.06238	19,487
Tier 3 1,000,000 - 2,000,000	149,105			0.03773	5,625
Tier 4 >2,000,000	458,470			0.02011	9,222
Subtotal Distribution Service Volumetric	1,156,023	0.04265	49,302	0.05030	58,152
Total Distribution Service Revenue	**1,156,023**	**0.05157**	**59,614**	**0.05444**	**62,939**
TRANSMISSION SERVICE					
Customer Charge	22	Varied	386	$700.00	189
Volumetric Rates					
Tier 1 0 - 2,000,000	24,319			0.05448	1,325
Tier 2 >2,000,000	276,414			0.01214	3,356
Subtotal Transmission Service Volumetric	300,734	0.02579	7,756	0.01556	4,681
Total Transmission Service Revenue	**300,734**	**0.02708**	**8,143**	**0.01619**	**4,869**
Total Noncore Commercial & Industrial	**1,456,757**	**0.04651**	**67,757**	**0.04655**	**67,809**
ITCS	**1,456,757**	**0.01527**	**22,248**	**0.00793**	**11,551**

TABLE 6

NATURAL GAS VEHICLE (NGV) RATES

SOUTHERN CALIFORNIA GAS COMPANY
2000 Biennial Cost Allocation Proceeding

	Costs (M$)	BCAP Rates ¢/therm
CUSTOMER RELATED		
NUMBER OF CUSTOMERS		
MARGINAL CUSTOMER COST		
MARGINAL CUSTOMER COST REVENUE	100	0.412
COMMON DISTRIBUTION - MEDIUM PRESSURE		
MEDIUM PRESSURE PEAK DAY DEMAND (MMCFD)	6.57	
MARGINAL DISTRIBUTION COST	82.7713	
MARGINAL DISTRIBUTION COST REVENUE	543	2.232
COMMON DISTRIBUTION - HIGH PRESSURE		
HIGH PRESSURE PEAK MONTH DEMAND (MMCF)	199.72	
MARGINAL DISTRIBUTION COST	0.6910	
MARGINAL DISTRIBUTION COST REVENUE	138	0.567
TOTAL COMMON DISTRIBUTION COST REVENUE	682	2.799
TRANSMISSION		
COLD YEAR THROUGHPUT (MDTH)	2,435	
MARGINAL TRANSMISSION COST	0.0653	
TOTAL TRANSMISSION COST REVENUE	159	0.653
STORAGE		
INVENTORY:		
INVENTORY RESERVATION (MMCF)		
MARGINAL INVENTORY COST		
MARGINAL INVENTORY COST REVENUE		
INJECTION CAPACITY:		
INJECTION RESERVATION (MMCFD)		
MARGINAL INJECTION COST		
MARGINAL INJECTION CAPACITY COST REVENUE		
VARIABLE INJECTION COST:		
INJECTIONS (MDTH)		
VARIABLE O&M COST		
TOTAL VARIABLE INJECTION COST REVENUE		
WITHDRAWAL CAPACITY:		
WITHDRAWAL RESERVATION (MMCFD)	6.57	
MARGINAL WITHDRAWAL COST	10.6895	
MARGINAL WITHDRAWAL CAP. COST REVENUE	70	0.288
VARIABLE WITHDRAWAL COST:		
WITHDRAWALS (MDTH)		
VARIABLE O&M COST		
TOTAL VARIABLE WITHDRAWAL COST REVENUE		
SUBTOTAL - SEASONAL STORAGE	70	0.288
MARGINAL LOAD BALANCING COST REVENUE		
COMPANY USE GAS: TRANSMISSION	26	0.106
SYSTEM MARGINAL COST REVENUE	**1,037**	**4.258**
SCALED LRMC REVENUE	**1,736**	**7.131**
MARKETING(excluding DSM)		
SDG&E Moreno Credit		
MARGINAL COST REVENUE W/MKTG & ARCO	1,736	7.131
UNCOLLECTIBLES	8	0.035
TOTAL ALLOCATED MARGIN (M$)	**1,745**	**7.166**
Pipeline Demand	852	3.499
Company Use (Storage & Other)	29	0.120
Fully Loaded LRMC plus Pipeline Demand & Co Use	2,626	**10.785**
Core Procurment Transportation Costs	50	0.284
Fully Loaded Procurement Transportation Rate	2,676	**11.069**
AVERAGE YEAR THROUGHPUT, MDth	2,435	

TABLE 7

Electric Generation Cost Allocation Segmentation

SOUTHERN CALIFORNIA GAS COMPANY

2000 Biennial Cost Allocation Proceeding

Line #	Description	Total
	CUSTOMER RELATED	
1	NUMBER OF CUSTOMERS	238
2	MARGINAL CUSTOMER COST	22.82724
3	MARGINAL CUSTOMER COST REVENUE	5,433
	COMMON DISTRIBUTION - MEDIUM PRESSURE	
4	MEDIUM PRESSURE PEAK DAY DEMAND (MMCFD)	19
5	MARGINAL DISTRIBUTION COST	
6	MARGINAL DISTRIBUTION COST REVENUE	1,532
	COMMON DISTRIBUTION - HIGH PRESSURE	
7	HIGH PRESSURE PEAK MONTH DEMAND (MMCF)	4,434
8	MARGINAL DISTRIBUTION COST	
9	MARGINAL DISTRIBUTION COST REVENUE	3064
10	TOTAL COMMON DISTRIBUTION COST REVENUE	4,596
	TRANSMISSION	
11	COLD YEAR THROUGHPUT (MDTH)	294,426
12	MARGINAL TRANSMISSION COST	
13	TOTAL TRANSMISSION COST REVENUE	19217
	STORAGE	
14	SUBTOTAL - SEASONAL STORAGE	-
15	MARGINAL LOAD BALANCING COST REVENUE	5,861
16	COMPANY USE GAS: TRANSMISSION	3,130
17	SYSTEM MARGINAL COST REVENUE	38,236
18	SCALED LRMC REVENUE	58,615
19	MARKETING(excluding DSM)	1,601
20	SDG&E Moreno Credit	26
21	MARGINAL COST REVENUE W/MKTG	60,242
22	UNCOLLECTIBLES	302
23	TOTAL ALLOCATED MARGIN (M$)	60,544
24	TOTAL ALLOCATED MARGIN (¢/th)	2.056
25	EXCLUSIONS + EG ADJUSTMENT	39,240
26	TOTAL TRANSPORTATION COSTS (M$)	99,785
27	TOTAL TRANSPORTATION COSTS (¢/THERM)	3.389
28	AVERAGE YEAR THROUGHPUT, MDth	294,426

TABLE 8

COMMON SEMPRA-WIDE
ELECTRIC GENERATION TRANSPORTATION RATES

SOUTHERN CALIFORNIA GAS COMPANY

2000 Biennial Cost Allocation Proceeding

		1/01/2000 Rates		Estimated BCAP Authorized Rates	
	Throughput (Mth)	Rate ($/th)	Revenue (M$)	Rate ($/th)	Revenue (M$)
Annual Consumption 0-3000 Mth					
Customer Charge ($/Month)	172	$ -	-	$ 50.00	103
Volumetric Rate	48,406	0.02584	1,251	0.05740	2,779
ITCS	48,406	0.01527	739	0.00793	384
Total Volumetric Rate	48,406	0.04111	1,990	0.06533	3,162
Class Average Rate	48,406	0.04111	1,990	0.06747	3,266
Annual Consumption > 3000 Mth					
Customer Charge ($/Month)	66	$ -	-	$ -	-
Volumetric Rate	2,895,851	0.02584	74,825	0.02540	73,557
ITCS	2,895,851	0.01527	44,226	0.00793	22,962
Total	2,895,851	0.04111	119,051	0.03333	96,519
Total Electric Generation	2,944,257	0.04111	121,041	0.03389	99,785

TABLE 9

UNBUNDLED STORAGE RATES FOR EXISTING FACILITIES

SOUTHERN CALIFORNIA GAS COMPANY
2000 Biennial Cost Allocation Proceeding

	INJECTION	WITHDRAWAL	INVENTORY
	$/Mcfd	$/Mcfd	$/Mcf
MARGINAL COST	18.611	10.689	0.197
SCALING	9.32%	9.32%	9.32%
TOTAL ALLOCATED MARGIN	20.347	11.686	0.216
MARKETING COSTS	0.144	0.083	0.002
TARIFF RESERVATION RATE	20.491	11.769	0.217
	$/Dth/d	$/Dth/d	$/Dth
Retail Rates			
TARIFF RESERVATION RATE	20.169	11.584	0.214
DAILY RATE	0.09425	0.07671	
VARIABLE RATE, $/Dth	0.01273	0.01773	NA
Wholesale Rates			
TARIFF RESERVATION RATE	20.070	11.527	0.213
DAILY RATE	0.09379	0.07634	
VARIABLE RATE, $/Dth	0.01267	0.01765	

TABLE 10

SUMMARY OF COST ALLOCATION AND REVENUE REQUIREMENTS (M$)

Page 1

SOUTHERN CALIFORNIA GAS COMPANY

2000 Biennial Cost Allocation Proceeding

LINE #	DESCRIPTION	CORE	RETAIL NONCORE	EOR	NONCORE WHOLESALE	NONCORE INTERNATIONAL	UNBUNDLED STORAGE	UNALLOCATED COSTS TO NSBA	SYSTEM TOTAL
1	MARGINAL CUSTOMER COST REVENUE	348,220	7,536	737	238	22	N/A	0	356,752
2	MARGINAL MEDIUM PRESSURE DISTRIBUTION COST REVENUE	246,369	14,130	33	0	0	N/A	0	260,532
3	MARGINAL HIGH PRESSURE DISTRIBUTION COST REVENUE	35,361	10,276	185	0	0	N/A	0	45,823
4	MARGINAL TRANSMISSION COST REV.	24,738	28,804	3,151	11,226	241	N/A	0	68,160
5	STORAGE LOAD BALANCING COST	475	7,850	1,422	961	42	N/A	0	10,751
6	SEASONAL STORAGE COSTS	42,554	0	0	0	0	19,074	0	61,628
7	COMPANY USE TRANSMISSION	3,613	4,678	513	1,763	39	N/A	0	10,606
8	SYSTEM MARGINAL COST REVENUE	701,331	73,275	6,042	14,188	344	19,074	0	814,253
9	SCALING MARKUP:	473,208	49,406	14,110	9,566	232	1,674	11,187	559,382
10	MARKETING COSTS	18,703	4,609	375	242	60	148	0	24,137
11	SDG&E MORENO CREDIT	519	54	N/A	(573)	0	N/A	N/A	0
12	SCALED SYSTEM MARGINAL COST REV.	1,193,760	127,344	20,527	23,423	636	20,895	11,187	1,397,772
13	UNCOLLECTIBLES	5,983	638	0	0	0	105	0	6,726
14	TOTAL ALLOCATED MARGIN	1,199,744	127,982	20,527	23,423	636	21,000	11,187	1,404,498
15	Total Margin w/o Transmission Company Use	1,196,131	123,304	20,014	21,659	597	21,000	11,187	1,393,892

TABLE 10

SUMMARY OF COST ALLOCATION AND REVENUE REQUIREMENTS (M$)

Page 2

SOUTHERN CALIFORNIA GAS COMPANY

LINE #	DESCRIPTION	CORE	RETAIL NONCORE	EOR	NONCORE WHOLESALE	NONCORE INTERNATIONAL	UNBUNDLED STORAGE	UNALLOCATED COSTS TO NSBA	SYSTEM TOTAL
	OTHER OPERATING COSTS AND REVENUES								
16a	Exchange Revenues & Interutility Transactions	117	137	0	53	1.1	N/A	N/A	308
16b	Schedule IB Service Revenue Credit	0	0	0	0	-	N/A	N/A	0
17	Core Brokerage Fee Adjustment	(6,508)	0	N/A	N/A	N/A	N/A	N/A	(6,508)
18	Noncore Brokerage Fee Adjustment	N/A	(60)	N/A	(23)	(0.5)	N/A	N/A	(83)
19	Marketing Exclusions: DSM & DAP	46,703	100	0	0	-	N/A	N/A	46,802
20	Exclusion RD&D	453	47	0	9	0.2	N/A	N/A	510
21	Intervenor Compensation	217	281	0	106	2.3	N/A	N/A	607
22	Fuel Cell Equipment Fee Revenues	(345)	(36)	0	(7)	(0.2)	N/A	N/A	(389)
23	Company Use Gas: Storage	3,494	1,220	134	460	10.0	N/A	N/A	5,317
24	Other Company Use Gas	275	356	39	134	2.9	N/A	N/A	806
25	Unaccounted For Gas	23,645	5,087	2,077	1,948	17.9	N/A	N/A	32,775
26	Carrying Cost Storage Inv.: Load Balancing	0	65	0	22	0.5	N/A	N/A	88
27	Well Incidents and Surface Leaks	151	6	0	2	0.0	0	N/A	159
	TRANSITION COSTS								
28	MPO Transition Cost Adjustment	0	0	0	0	0	N/A	N/A	0
29	Pitco/Popco Transition Cost	(8,349)	(10,812)	0	(4,075)	(89)	N/A	N/A	(23,325)
30	Interstate Trans. Cost Surcharge Accunt (ITCS)	11,559	34,896	0	13,152	287	N/A	N/A	59,895
	BALANCING AND TRACKING ACCOUNTS								
31	Pitas Point F&U Account	(13)	(17)	0	(6)	(0)	N/A	N/A	(36)
32	NGV Account (NGVA)	3,666	4,747	0	237	40	N/A	N/A	8,689
	Noncore Storage Balancing Account (NSBA)								
33	Subscribed Storage Revenue Subaccount	N/A	459	0	173	4	N/A	N/A	636
34	Storage Transition and Bypass Subaccount	(898)	(1,163)	0	(438)	(10)	N/A	N/A	(2,509)
35	Zone Rate Credit Limitation Memorandum Account (ZRCLMA)	(1,308)	(137)	0	(26)	(1)	N/A	N/A	(1,472)
36	N/C Brokerage Fee Balancing Account (BFBA)	N/A	639	0	241	5	N/A	N/A	885
37	Interim Zone Rate Credit Account (IZRCA)	0	0	0	0	0	N/A	N/A	0
38	Hazardous Substances Cost Recovery Account (HSCRA)	3,258	4,218	0	1,590	35	N/A	N/A	9,101
39	Conservation Expense Account (CEA)	0	0	0	0	0	N/A	N/A	0
40	RD&D Expense Account (RDDEA)	(7,228)	(755)	0	(146)	(4)	N/A	N/A	(8,132)
41	Core Fixed Cost Account (CFCA)	(132,043)	0	N/A	N/A	N/A	N/A	N/A	(132,043)
42	Economic Practicality Shortfall Memo. Acct (EPSMA)	N/A	(1,639)	N/A	N/A	N/A	N/A	N/A	(1,639)
43	Enhanced Oil Recovery Account (EORA)	14,140	1,204	N/A	232	6	N/A	N/A	15,581
44	Minimum Purchase Obligation (MPO)	N/A	2,469	N/A	931	20	N/A	N/A	3,420
45	Pipeline Demand Charges (PDC)	N/A	(1)	N/A	(1)	(0)	N/A	N/A	(2)
46	Carrying Cost of Storage (CCS)	N/A	51	N/A	0	0	N/A	N/A	51
47	Take-or-Pay (TOP)	N/A	(0)	N/A	(0)	(0)	N/A	N/A	(0)
48	Non-Core Fixed Cost Account (NFCA)	N/A	1,686	N/A	635	14	N/A	N/A	2,335
49	Non-Core Cost/Revenue Memo Acct(NCRMA)	0	0	0	0	0	N/A	N/A	0
50a	Catastrophic Event Memorandum Account(CEMA)	0	0	0	0	0	N/A	N/A	0
50b	CEMA Double Refund Tracking Acct (CEMA-DRT)	0	0	0	0	0	N/A	N/A	0
50c	PBOPS	(7,898)	(825)	0	(159)	(4)	N/A	N/A	(8,887)
51	Auditing Expense Account (AEA)	0	0	0	0	0	N/A	N/A	0
53	Research Royalty Memorandum Account (RRMA)	(246)	(26)	0	(5)	(0)	N/A	N/A	(277)
54b	Environmental Fee Account (EFA)	0	0	0	0	0	N/A	N/A	0
54a	Affiliate Transaction Tracking Account (AFTA)	(99)	(10)	0	(2)	(0)	N/A	N/A	(111)
55	Fuel Cell Proceeds Memorandum Account (FCPMA)	0	0	0	0	0	N/A	N/A	0

TABLE 10

SUMMARY OF COST ALLOCATION AND REVENUE REQUIREMENTS (M$)

Page 3

SOUTHERN CALIFORNIA GAS COMPANY

LINE #	DESCRIPTION	CORE	RETAIL NONCORE	EOR	NONCORE WHOLESALE	NONCORE INTERNATIONAL	UNBUNDLED STORAGE	UNALLOCATED COSTS TO NSBA	SYSTEM TOTAL
56	Pipeline Demand Charges: EP & TW Traditional - Core	118,936	N/A	N/A	N/A	N/A	N/A	N/A	118,936
57	TOTAL TRANSPORTATION REVENUE REQUIREMENT	1,261,420	170,169	22,777	38,461	974	21,000	11,187	1,525,987
58	TOTAL TARIFFED REVENUE REQUIREMENTS	1,261,420	170,169	N/A	38,461	974	21,000	11,187	1,503,210
59	Average Year Throughput (Mdth)	339,873	440,101	N/A	166,679	3,642	N/A	N/A	950,295
60	TARIFFED TRANSPORTATION RATE (¢/th)	37.114	3.867	N/A	2.307	2.675	N/A	0.000	15.818
	GAS PROCUREMENT RELATED COSTS								
61	Carrying Cost of Storage Inv.: Other (CCSI)	1,648							
62	Pipeline Demand Charges: San Juan Lateral only	7,544							
63	Total Procurement Related Costs	9,193							
64	Total Procurement Related Rate (¢/th)	0.284							
65	Sales Volumes (Mdth)	323,780							
66	Total Procurement Customer, Transmission Rate (¢/th)	37.866							

TABLE 11: CORE REVENUE ALLOCATION

SOUTHERN CALIFORNIA GAS COMPANY

2000 Biennial Cost Allocation Proceeding

LRMC COST ALLOCATION (M$): MARGINAL COST REVENUE

LINE #	MARGINAL COST COMPONENTS	CORE RESIDEN-TIAL	CORE COM/IND G10	CORE COM/IND G20	CORE COM/IND NonRes A/C	CORE COM/IND Gas Engine	Total Core
		(b)	(c)	(d)	(e)	(f)	(g)
	CUSTOMER RELATED						
(1)	NUMBER OF CUSTOMERS	4,695,661	200,385	95	18	698	4,896,857
(2)	MARGINAL CUSTOMER COST	0.06397	0.22958	1.08767	1.95658	2.41203	
(3)	**MARGINAL CUSTOMER COST REVENUE**	300,394	46,004	103	35	1,684	348,220
	COMMON DISTRIBUTION - MEDIUM PRESSURE						
(4)	MEDIUM PRESSURE PEAK DAY DEMAND (MMCFD)	2,486	475	15	0	1	2,977
(5)	MARGINAL DISTRIBUTION COST	82.7713	82.7713	82.7713	82.7713	82.7713	
(6)	MARGINAL DISTRIBUTION COST REVENUE	205,780	39,294	1,210	24	61	246,369
	COMMON DISTRIBUTION - HIGH PRESSURE						
(7)	HIGH PRESSURE PEAK MONTH DEMAND (MMCF)	41,110	9,591	434	9	27	51,171
(8)	MARGINAL DISTRIBUTION COST	0.6910	0.6910	0.6910	0.6910	0.6910	
(9)	MARGINAL DISTRIBUTION COST REVENUE	28,408	6,628	300	6	19	35,361
(10)	**TOTAL COMMON DISTRIBUTION COST REVENUE**	234,189	45,921	1,510	31	80	281,730
	TRANSMISSION						
(11)	COLD YEAR THROUGHPUT (MDTH)	288,850	83,645	4,800	120	1,604	379,019
(12)	MARGINAL TRANSMISSION COST	0.0653	0.0653	0.0653	0.0653	0.0653	
(13)	**TOTAL TRANSMISSION COST REVENUE**	18,853	5,459	313	8	105	24,738

TABLE 11: CORE REVENUE ALLOCATION

Page 2

SOUTHERN CALIFORNIA GAS COMPANY

2000 Biennial Cost Allocation Proceeding

LRMC COST ALLOCATION (M$): MARGINAL COST REVENUE

LINE #	MARGINAL COST COMPONENTS	CORE RESIDEN-TIAL	CORE COM/IND G10	CORE COM/IND G20	CORE COM/IND NonRes A/C	CORE COM/IND Gas Engine	Total Core
		(b)	(c)	(d)	(e)	(f)	(g)
	STORAGE						
	INVENTORY:						
(14)	INVENTORY RESERVATION (MMCF)	59,324	10,003	672	0	0	70,000
(15)	MARGINAL INVENTORY COST	0.1972	0.1972	0.1972	0.1972	0.1972	
(16)	MARGINAL INVENTORY COST REVENUE	11,700	1,973	133	0	0	13,805
	INJECTION CAPACITY:						
(17)	INJECTION RESERVATION (MMCFD)	277	47	3	0	0	327
(18)	MARGINAL INJECTION COST	18.611	18.611	18.611	18.611	18.611	
(19)	MARGINAL INJECTION CAPACITY COST REVENUE	5,159	870	58	0	0	6,088
	VARIABLE INJECTION COST:						
(20)	INJECTIONS (MDTH)	59,993	10,116	680	7	323	71,120
(21)	VARIABLE O&M COST	0.012	0.012	0.012	0.006	0.006	
(22)	TOTAL VARIABLE INJECTION COST REVENUE	699	118	8	0	2	826
	WITHDRAWAL CAPACITY:	0	0	0	0	0	0
(23)	WITHDRAWAL RESERVATION (MMCFD)	1,616	309	10	0	0	1,935
(24)	MARGINAL WITHDRAWAL COST	10.689	10.689	10.689	10.689	10.689	
(25)	MARGINAL WITHDRAWAL CAP. COST REVENUE	17,276	3,299	102	2	5	20,684
	VARIABLE WITHDRAWAL COST:						
(26)	WITHDRAWALS (MDTH)	59,993	10,116	680	7	323	71,120
(27)	VARIABLE O&M COST	0.016	0.016	0.016	0.008	0.008	
(28)	TOTAL VARIABLE WITHDRAWAL COST REVENUE	973	164	11	0	3	1,151
(29)	**SUBTOTAL - SEASONAL STORAGE**	35,807	6,424	312	2	10	42,554
(30)	MARGINAL LOAD BALANCING COST REVENUE	356	110	7	0	2	475
(31)	COMPANY USE GAS: TRANSMISSION	2,707	837	50	1	17	3,613
(32)	**SYSTEM MARGINAL COST REVENUE**	**592,307**	**104,756**	**2,295**	**77**	**1,897**	**701,331**
(33)	**SCALED LRMC REVENUE**	**991,953**	**175,437**	**3,843**	**129**	**3,177**	**1,174,539**
(34a)	MARKETING(excluding DSM)	14,202	4,330	135	3	33	18,703
(34b)	SDG&E Moreno Credit	438	78	2	0	1	519
(35)	**MARGINAL COST REVENUE W/MKTG & ARCO**	1,006,593	179,845	3,980	132	3,211	1,193,760
(36)	UNCOLLECTIBLES	5,045	901	20	1	16	5,983
(37)	**TOTAL ALLOCATED MARGIN (M$)**	**1,011,638**	**180,746**	**4,000**	**133**	**3,227**	**1,199,744**
(38)	**TOTAL ALLOCATED MARGIN (¢/th)**	39.721	22.944	8.536	11.085	20.119	35.300
(39)	**AVERAGE YEAR THROUGHPUT, MDth**	254,685	78,778	4,685	120	1,604	339,873

Core Scaling Factor = 1.674728

TABLE 11: CORE REVENUE ALLOCATION

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SOUTHERN CALIFORNIA GAS COMPANY

2000 Biennial Cost Allocation Proceeding

OTHER OPERATING COST AND TRANSITION COST ALLOCATION (M$)

OTHER COST COMPONENTS

Line	Forecast Period Costs	Residential Cost	G-10 Cost	G-20 Cost	NonRes A/C Cost	Gas Engine Cost	Total Core Cost
		(b)	(c)	(d)	(e)	(f)	(g)
	TRANSPORTATION REVENUE REQ.						
(40a)	Subtotal - Margin - Base	1,011,638	180,746	4,000	133	3,227	1,199,744
	Other Operating Costs and Revenues						
(40b)	Exchange Revenues & Interutility Transactions	89	26	1	0	0	117
(40c)	Schedule IB Service Revenue Credit	-	-	-	-	-	-
(41)	Core Brokerage Fee Adjustment	(4,877)	(1,508)	(90)	(2)	(31)	(6,508)
(42)	Noncore Brokerage Fee Adjustment	N/A	N/A	N/A	N/A	N/A	N/A
(43a)	Marketing Exclusions: DSM & DAP	31,352	15,167	112	1	72	46,703
(43b)	RD&D "Common Good"	383	68	1	0	1	453
(44)	Fuel Cell Equipment Revenues	(292)	(52)	(1)	(0)	(1)	(345)
(45)	Company Use Gas: Storage	2,858	581	37	1	16	3,494
(46)	Other Company Use Gas	206	64	4	0	1	275
(47)	Unaccounted For Gas	23,072	685	(121)	1	8	23,645
(48)	Carrying Cost Storage Inv.: Load Balancing	-	-	-	-	-	-
(49)	Well Incidents & Surface Leaks	128	22	1	-	-	151
(50)	Subtotal Other Operating Costs and Revenues	52,920	15,052	(55)	0	67	67,984
	Transition Costs						
(51)	MPO Transition Cost Adjustment	-	-	-	-	-	-
(52)	Pitco/Popco Transition Costs	(6,257)	(1,935)	(115)	(3)	(39)	(8,349)
(53)	Interstate Trans. Cost Surcharge Accunt (ITCS) [1]	8,662	2,679	159	4	55	11,559
(54)	Subtotal Transition Costs	2,405	744	44	1	15	3,210

[1] Average Year Throughput, Core 10% of PL Demand Cap

TABLE 11: CORE REVENUE ALLOCATION

SOUTHERN CALIFORNIA GAS COMPANY

2000 Biennial Cost Allocation Proceeding

BALANCING, TRACKING AND MEMORANDUM ACCOUNTS ALLOCATION (M$)

OTHER COST COMPONENTS

Line	Forecast Period Costs	Residential Cost (b)	G-10 Cost (c)	G-20 Cost (d)	NonRes A/C Cost (e)	Gas Engine Cost (f)	Total Core Cost (g)
	Balancing, Tracking & Memorandum Accounts:						
(55)	Pitas Point F&U Account (PPF&UA)	(10)	(3)	(0)	(0)	(0)	(13)
(56)	NGV Account (NGVA)	2,747	850	51	1	17	3,666
	Noncore Storage Balancing Account (NSBA)						
(57)	Subscribed Storage Revenue Account	N/A	N/A	N/A	N/A	N/A	N/A
(58)	Storage Transition and Bypass Subaccount	(673)	(208)	(12)	(0)	(4)	(898)
(59)	Zone Rate Credit Limitation Memo Acct(ZRCLMA)	(1,105)	(195)	(4)	(0)	(4)	(1,308)
(60)	N/C Brokerage Fee Balancing Account (BFBA)	N/A	N/A	N/A	N/A	N/A	N/A
(61)	Interim Zone Rate Credit Account (IZRCA)	-	-	-	-	-	-
(62)	Hazardous Substan. Cost Recov. Acct (HSCRA)	2,441	755	45	1	15	3,258
(63)	Conservation Expense Account (CEA)	-	-		-	-	-
(64)	R D & D Expense Account (RDDEA)	(6,104)	(1,080)	(24)	(1)	(20)	(7,228)
(65)	Core Fixed Cost Account (CFCA)	(98,947)	(30,606)	(1,820)	(47)	(623)	(132,043)
(66)	Economic Practicality Shortfall Memo. Acct (EPSMA)	N/A	N/A	N/A	N/A	N/A	N/A
(67)	Enhanced Oil Recovery Account-Core(EORA)	11,942	2,112	46	2	38	14,140
(68)	Enhanced Oil Recovery Account-N/C (EORA)	N/A	N/A	N/A	N/A	N/A	N/A
(69)	Minimum Purchase Obligation (MPO)	N/A	N/A	N/A	N/A	N/A	N/A
(70)	Pipeline Demand Charges (PDC)	N/A	N/A	N/A	N/A	N/A	N/A
(71)	Carrying Cost of Storage (CCS)	N/A	N/A	N/A	N/A	N/A	N/A
(72)	Take-or-Pay (TOP)	N/A	N/A	N/A	N/A	N/A	N/A
(73)	Non-Core Fixed Cost Account (NFCA)	N/A	N/A	N/A	N/A	N/A	N/A
(74a)	Non-Core Cost/Revenue Memo Acct(NCRMA)	-	-	-	-	-	-
(74b)	Catastrophic Event Memorandum Account(CEMA)	-	-	-	-	-	-
(74bb)	CEMA Double Refund Tracking Acct (CEMA-DRT)	-	-	-	-	-	-
(74bbb)	PBOPS	(6,671)	(1,180)	(26)	(1)	(21)	(7,898)
(74c)	Intervenor Compensation	163	50	3	0	1	217
(75a)	Auditing Expense Account (AEA)	-	-		-	-	-
(75c)	Research Royalty Memorandum Account (RRMA)	(208)	(37)	(1)	(0)	(1)	(246)
(75d)	Environmental Fee Account (EFA)	-	-	-	-	-	-
(75e)	Affiliate Transaction Tracking Account (AFTA)	(83)	(15)	(0)	(0)	(0)	(99)
(75f)	Fuel Cell Proceeds Memorandum Acct (FCPMA)	-	-	-	-	-	-
(75)	Subtotal Balancing and Tracking Accounts	(96,508)	(29,556)	(1,743)	(45)	(601)	(128,453)
(76)	**Subtotal-Transportation Revenue Requirement**	970,455	166,986	2,246	90	2,708	1,142,484
(77)	Subtotal- Transportation Revenue Requirement (¢/th)	38.104	21.197	4.793	7.468	16.885	33.615

TABLE 11: CORE REVENUE ALLOCATION
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SOUTHERN CALIFORNIA GAS COMPANY
2000 Biennial Cost Allocation Proceeding

SUMMARY TRANSPORTATION COST AND PROCUREMENT COST ALLOCATION (M$)

OTHER COST COMPONENTS

Line	Forecast Period Costs	Residential Cost (b)	G-10 Cost (c)	G-20 Cost (d)	NonRes A/C Cost (e)	Gas Engine Cost (f)	Total Core Cost (g)
(78)	**Subtotal-Transportation Revenue Requirement**	**970,455**	**166,986**	**2,246**	**90**	**2,708**	**1,142,484**
(79)	Pipeline Demand Charges-EP&TW Trad-Core	89,125	27,568	1,640	42	561	118,936
(80)	UEG/Cogeneration Parity Adjustment	0	0	0	0	0	0
(81)	Gas Engine Rate Cap Adjustment	0	0	0	0	0	0
(82)	**TOTAL TRANS. REVENUE REQUIREMENT**	**1,059,580**	**194,554**	**3,885**	**132**	**3,270**	**1,261,420**
	Tariffed Rates						
(83)	Total Transportation Costs (Line 46) Less: EOR	1,059,580	194,554	3,885	132	3,270	1,261,420
(84)	Core Averaging: @ 25%	(25,431)	25,431	-	-	-	-
(85)	**TOTAL TRANS. REV. REQ. w/o EOR**	**1,034,148**	**219,985**	**3,885**	**132**	**3,270**	**1,261,420**
(86)	Average Year Throughput (MDth)	254,685	78,778	4,685	120	1,604	339,873
(87)	**TARIFFED TRANSPORTATION RATES (¢/th)**	**40.605**	**27.925**	**8.293**	**10.967**	**20.384**	**37.114**
(88)	**Noncore ITCS Rate (¢/th)**						
	Gas Procurement Related Costs						
(89)	Carrying Cost Storage Inv: Other (CCSI)	1,284	342	15	1	8	1,648
(90)	Core Pipeline Demand Charges (SJ Lateral)	5,875	1,564	68	2	36	7,544
(91)	Subtotal Procurement Related Costs	7,159	1,905	82	3	43	9,193
(92)	**Gas Procurement Related Cost (¢/th)**	**0.284**	**0.284**	**0.284**	**0.284**	**0.284**	**0.284**
(93)	**Total Procurement Related Rate (¢/th)**	**40.889**	**28.209**	**8.577**	**11.251**	**20.668**	**37.866**
(94)	Average Year Sales (MDth)	252,138	67,110	2,901	106	1,524	323,780
(95)	**Total Procurement Customer, Transmission Rate (¢/th)**	**1,030,966**	**189,309**	**2,488**	**119**	**3,150**	**1,226,031**
	Total Core Transportation Revenue Requirement	1,041,307	221,890	3,968	135	3,313	1,270,613

TABLE 12: NONCORE & WHOLESALE REVENUE ALLOCATION

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SOUTHERN CALIFORNIA GAS COMPANY

2000 Biennial Cost Allocation Proceeding

LRMC COST ALLOCATION (M$): MARGINAL COST REVENUE

LINE #	MARGINAL COST COMPONENTS	NONCORE COM/IND G30	NONCORE COGEN G50	NONCORE UEG G60	NONCORE EOR G40	NONCORE Total Noncore	WHOLESALE Long Beach	WHOLESALE SDG&E	WHOLESALE Southwest Gas	WHOLESALE Vernon	Total Wholesale
		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	CUSTOMER RELATED										
(1)	NUMBER OF CUSTOMERS	1,162	215	23	67	1,467	1	1	1	1	4
(2)	MARGINAL CUSTOMER COST	4.5847	5.9127	40.6704	11.0049		71.3611	99.436	43.2843	23.7549	
(3)	**MARGINAL CUSTOMER COST REVENUE**	5,329	1,271	935	737	8,273	71	99	43	24	238
	COMMON DISTRIBUTION - MEDIUM PRESSURE										
(4)	MEDIUM PRESSURE PEAK DAY DEMAND (MMCFD)	152	19	0	0	171	0	0	0	0	0
(5)	MARGINAL DISTRIBUTION COST	82.7713	82.7713	82.7713	82.7713		82.7713	82.7713	82.7713	82.7713	
(6)	MARGINAL DISTRIBUTION COST REVENUE	12,598	1,532	0	33	14,163	0	0	0	0	0
	COMMON DISTRIBUTION - HIGH PRESSURE										
(7)	HIGH PRESSURE PEAK MONTH DEMAND (MMCF)	10,437	3,100	1,334	268	15,139	0	0	0	0	0
(8)	MARGINAL DISTRIBUTION COST	0.6910	0.6910	0.6910	0.6910		0.6910	0.6910	0.6910	0.6910	
(9)	MARGINAL DISTRIBUTION COST REVENUE	7,213	2,142	922	185	10,462	0	0	0	0	0
(10)	**TOTAL COMMON DISTRIBUTION COST REVENUE**	19,811	3,674	922	219	24,625	0	0	0	0	0
	TRANSMISSION										
(11)	COLD YEAR THROUGHPUT (MDTH)	146,890	82,735	211,691	48,271	489,586	8,361	148,753	9,683	5,192	171,988
(12)	MARGINAL TRANSMISSION COST	0.0653	0.0653	0.0653	0.0653		0.0653	0.0653	0.0653	0.0653	
(13)	**TOTAL TRANSMISSION COST REVENUE**	9,587	5,400	13,817	3,151	31,955	546	9,709	632	339	11,226

TABLE 12: NONCORE & WHOLESALE REVENUE ALLOCATION

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SOUTHERN CALIFORNIA GAS COMPANY

2000 Biennial Cost Allocation Proceeding

LRMC COST ALLOCATION (M$): MARGINAL COST REVENUE

LINE #	MARGINAL COST COMPONENTS	NONCORE COM/IND G30 (b)	NONCORE COGEN G50 (c)	NONCORE UEG G60 (d)	NONCORE EOR G40 (e)	NONCORE Total Noncore (f)	WHOLESALE Long Beach (g)	WHOLESALE SDG&E (h)	WHOLESALE Southwest Gas (i)	WHOLESALE Vernon (j)	WHOLESALE Total Wholesale (k)
	STORAGE										
	INVENTORY:										
(14)	INVENTORY RESERVATION (MMCF)	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0
(15)	MARGINAL INVENTORY COST	N/A	N/A	N/A	N/A	N/A	0.1972	0.1972	0.1972	0.1972	
(16)	MARGINAL INVENTORY COST REVENUE	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0
	INJECTION CAPACITY:										
(17)	INJECTION RESERVATION (MMCFD)	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0
(18)	MARGINAL INJECTION COST	N/A	N/A	N/A	N/A	N/A	18.611	18.611	18.611	18.611	
(19)	MARGINAL INJECTION CAPACITY COST REVENUE	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0
	VARIABLE INJECTION COST:										
(20)	INJECTIONS (MDTH)	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0
(21)	VARIABLE O&M COST	N/A	N/A	N/A	N/A	N/A	0.012	0.012	0.012	0.012	
(22)	TOTAL VARIABLE INJECTION COST REVENUE	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0
	WITHDRAWAL CAPACITY:	0	0	0	0	0	0	0	0	0	0
(23)	WITHDRAWAL RESERVATION (MMCFD)	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0
(24)	MARGINAL WITHDRAWAL COST	N/A	N/A	N/A	N/A	N/A	10.689	10.689	10.689	10.689	
(25)	MARGINAL WITHDRAWAL CAP. COST REVENUE	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0
	VARIABLE WITHDRAWAL COST:										
(26)	WITHDRAWALS (MDTH)	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0
(27)	VARIABLE O&M COST	N/A	N/A	N/A	N/A	N/A	0.016	0.016	0.016	0.016	
(28)	TOTAL VARIABLE WITHDRAWAL COST REVENUE	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0
(29)	**SUBTOTAL - SEASONAL STORAGE**	0	0	0	0	0	0	0	0	0	0
(30)	MARGINAL LOAD BALANCING COST REVENUE	1,989	1,130	4,731	1,422	9,272	151	652	128	30	961
(31)	COMPANY USE GAS: TRANSMISSION	1,549	879	2,250	513	5,192	82	1,529	97	55	1,763
(32)	**SYSTEM MARGINAL COST REVENUE**	38,265	12,355	22,655	6,042	79,317	850	11,990	900	447	14,188
(33)	**SCALED LRMC REVENUE**	64,065	20,685	37,931	20,152	142,833	1,424	20,075	1,508	748	23,754
(34a)	MARKETING(excluding DSM)	3,008	664	937	375	4,984	60	60	60	60	242
(34b)	SDG&E Moreno Credit	28	9	17	N/A	54	1	(575)	1	0	(573)
(35)	**MARGINAL COST REVENUE W/MKTG & ARCO**	67,102	21,358	38,884	20,527	147,871	1,485	19,560	1,569	809	23,423
(36)	UNCOLLECTIBLES	336	107	195	-	638	-	-	-	-	-
(37)	**TOTAL ALLOCATED MARGIN (M$)**	67,438	21,465	39,079	20,527	148,509	1,485	19,560	1,569	809	23,423
(38)	**TOTAL ALLOCATED MARGIN (¢/th)**	4.629	2.594	1.846	4.253	3.041	1.908	1.353	1.711	1.567	1.405
(39)	**AVERAGE YEAR THROUGHPUT, MDth**	145,676	82,735	211,691	48,271	488,372	7,782	144,568	9,167	5,162	166,679

Noncore Scaling Factor = 1.6742548

TABLE 12: NONCORE & WHOLESALE REVENUE ALLOCATION

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SOUTHERN CALIFORNIA GAS COMPANY

2000 Biennial Cost Allocation Proceeding

OTHER OPERATING COST AND TRANSITION COST ALLOCATION (M$)

Line	OTHER COST COMPONENTS Forecast Period Costs	Com/Ind Cost	Cogen Cost	UEG Cost	EOR Cost	Total Noncore Cost	Wholesale Long Beach Cost	Wholesale SDG&E Cost	Wholesale Southwest Gas	Wholesale Vernon Cost	Total Wholesale Cost
		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	TRANSPORTATION REVENUE REQ.										
(39)	Subtotal - Margin - Base	67,438	21,465	39,079	20,527	148,509	1,485	19,560	1,569	809	23,423
	Other Operating Costs and Revenues										
(40)	Exchange Revenues & Interutility Transactions	45	26	66	-	137	3	46	3	2	53
(40b)	Schedule IB Service Revenue Credit	-	-	-	-	-	-	-	-	-	-
(41)	Core Brokerage Fee Adjustment	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
(42)	Noncore Brokerage Fee Adjustment	(20)	(11)	(29)	N/A	(60)	(1)	(20)	(1)	(1)	(23)
(43a)	Marketing Exclusions: DSM & DAP	100	-	-	-	100	-	-	-	-	-
(43b)	RD&D "Common Good"	25	8	15	-	47	1	8	1	0	9
(44)	Fuel Cell Equipment Revenues	(19)	(6)	(11)	-	(36)	(0)	(6)	(0)	(0)	(7)
(45)	Company Use Gas: Storage	404	229	587	134	1,354	21	399	25	14	460
(46)	Other Company Use Gas	118	67	171	39	395	6	116	7	4	134
(47)	Unaccounted For Gas	774	1,565	2,748	2,077	7,164	128	1,637	158	25	1,948
(48)	Carrying Cost Storage Inv.: Load Balancing	21	12	31	-	65	1	19	1	1	22
(49)	Well Incidents & Surface Leaks	2	1	3	-	6	0	2	0	0	2
(50)	Subtotal Other Operating Costs and Revenues	1,450	1,891	3,580	2,250	9,171	159	2,201	194	46	2,599
	Transition Costs										
(51)	MPO Transition Cost Adjustment	-	-	-	-	-	-	-	-	-	-
(52)	Pitco/Popco Transition Costs	(3,579)	(2,032)	(5,200)	-	(10,812)	(190)	(3,534)	(224)	(126)	(4,075)
(53)	Interstate Trans. Cost Surcharge Accumt (ITCS) [1]	11,551	6,560	16,785	-	34,896	614	11,407	723	407	13,152
(54)	Subtotal Transition Costs	7,972	4,528	11,585	-	24,085	424	7,873	499	281	9,077

[1] Average Year Throughput, Core 10% of PL Demand Cap

TABLE 12: NONCORE & WHOLESALE REVENUE ALLOCATION

SOUTHERN CALIFORNIA GAS COMPANY

2000 Biennial Cost Allocation Proceeding

BALANCING, TRACKING AND MEMORANDUM ACCOUNTS ALLOCATION (M$)

OTHER COST COMPONENTS

Line	Forecast Period Costs	Com/Ind Cost	Cogen Cost	UEG Cost	EOR Cost	Total Noncore Cost	Wholesale Long Beach Cost	Wholesale SDG&E Cost	Wholesale Southwest Gas	Wholesale Vernon Cost	Total Wholesale Cost
		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Balancing, Tracking & Memorandum Accounts:										
(55)	Pitas Point F&U Account (PPF&UA)	(6)	(3)	(8)	-	(17)	(0)	(5)	(0)	(0)	(6)
(56)	NGV Account (NGVA)	1,571	892	2,283	-	4,747	84	-	98	55	237
	Noncore Storage Balancing Account (NSBA)										
(57)	Subscribed Storage Revenue Account	152	86	221	N/A	459	8	150	10	5	173
(58)	Storage Transition and Bypass Subaccount	(385)	(219)	(560)	-	(1,163)	(20)	(380)	(24)	(14)	(438)
(59)	Zone Rate Credit Limitation Memo Acct(ZRCLMA)	(71)	(23)	(42)	-	(137)	(2)	(22)	(2)	(1)	(26)
(60)	N/C Brokerage Fee Balancing Account (BFBA)	212	120	307	N/A	639	11	209	13	7	241
(61)	Interim Zone Rate Credit Account (IZRCA)	-	-	-	-	-	-	-	-	-	-
(62)	Hazardous Substan. Cost Recov. Acct (HSCRA)	1,396	793	2,029	-	4,218	74	1,379	87	49	1,590
(63)	Conservation Expense Account (CEA)	-	-	-	-	-	-	-	-	-	-
(64)	R D & D Expense Account (RDDEA)	(394)	(127)	(233)	-	(755)	(9)	(123)	(9)	(5)	(146)
(65)	Core Fixed Cost Account (CFCA)	-	-	-	N/A	-	N/A	N/A	N/A	N/A	
(66)	Economic Practicality Shortfall Memo. Acct (EPSMA)	(1,639)	N/A	N/A	N/A	(1,639)	N/A	N/A	N/A	N/A	-
(67)	Enhanced Oil Recovery Account-Core(EORA)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
(68)	Enhanced Oil Recovery Account-N/C (EORA)	628	203	372	N/A	1,204	14	196	15	7	232
(69)	Minimum Purchase Obligation (MPO)	817	464	1,188	N/A	2,469	43	807	51	29	931
(70)	Pipeline Demand Charges (PDC)	(0)	(0)	(1)	N/A	(1)	(0)	(0)	(0)	(0)	(1)
(71)	Carrying Cost of Storage (CCS)	17	10	24	N/A	51	-	-	-	-	-
(72)	Take-or-Pay (TOP)	(0)	(0)	(0)	N/A	(0)	(0)	(0)	(0)	(0)	(0)
(73)	Non-Core Fixed Cost Account (NFCA)	558	317	811	N/A	1,686	30	551	35	20	635
(74a)	Non-Core Cost/Revenue Memo Acct(NCRMA)	-	-	-	-	-	-	-	-	-	-
(74b)	Catastrophic Event Memorandum Account(CEMA)	-	-	-	-	-	-	-	-	-	-
(74bb)	CEMA Double Refund Tracking Acct (CEMA-DRT)	-	-	-	-	-	-	-	-	-	-
(74bbb)	PBOPS	(431)	(139)	(255)	-	(825)	(10)	(134)	(10)	(5)	(159)
(74c)	Intervenor Compensation	93	53	135	-	281	5	92	6	3	106
(75a)	Auditing Expense Account (AEA)	-	-	-	-	-	-	-	-	-	-
(75c)	Research Royalty Memorandum Account (RRMA)	(13)	(4)	(8)	-	(26)	(0)	(4)	(0)	(0)	(5)
(75d)	Environmental Fee Account (EFA)	-	-	-	-	-	-	-	-	-	-
(75e)	Affiliate Transaction Tracking Account (AFTA)	(5)	(2)	(3)	-	(10)	(0)	(2)	(0)	(0)	(2)
(75f)	Fuel Cell Proceeds Memorandum Acct (FCPMA)	-	-	-	-	-	-	-	-	-	-
(75)	Subtotal Balancing and Tracking Accounts	2,499	2,421	6,261	-	11,181	228	2,713	269	152	3,362
(76)	**Subtotal-Transportation Revenue Requirement**	79,360	30,304	60,505	22,777	192,945	2,295	32,347	2,531	1,288	38,461
(77)	Subtotal- Transportation Revenue Requirement (¢/th)	5.448	3.663	2.858	-	4.384	2.949	2.237	2.761	2.495	2.307

TABLE 12: NONCORE & WHOLESALE REVENUE ALLOCATION

SOUTHERN CALIFORNIA GAS COMPANY

2000 Biennial Cost Allocation Proceeding

SUMMARY TRANSPORTATION COST ALLOCATION (M$)

OTHER COST COMPONENTS

Line	Forecast Period Costs	Com/Ind Cost	Cogen Cost	UEG Cost	EOR Cost	Total Noncore Cost	Wholesale Long Beach Cost	Wholesale SDG&E Cost	Wholesale Southwest Gas	Wholesale Vernon Cost	Total Wholesale Cost
		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
(78)	**Subtotal-Transportation Revenue Requirement**	**79,360**	**30,304**	**60,505**	**22,777**	**192,945**	**2,295**	**32,347**	**2,531**	**1,288**	**38,461**
(79)	Pipeline Demand Charges-EP&TW Trad-Core	-	-	-	-	-	-	-	-	-	-
(80)	UEG/Cogeneration Parity Adjustment	0	(4,786)	4,786	N/A	(0)	0	0	0	0	0
(81)	Gas Engine Rate Cap Adjustment	0	0	0	N/A	0	0	0	0	0	0
(82)	**TOTAL TRANS. REVENUE REQUIREMENT**	**79,360**	**25,518**	**65,291**	**22,777**	**192,945**	**2,295**	**32,347**	**2,531**	**1,288**	**38,461**
	Tariffed Rates										
(83)	Total Transportation Costs (Line 46) Less: EOR	79,360	25,518	65,291	N/A	170,169	2,295	32,347	2,531	1,288	38,461
(84)	Core Averaging: @ 25%	-	-	-	N/A	-	-	-	-	-	-
(85)	**TOTAL TRANS. REV. REQ. w/o EOR**	**79,360**	**25,518**	**65,291**	**N/A**	**170,169**	**2,295**	**32,347**	**2,531**	**1,288**	**38,461**
(86)	Average Year Throughput (MDth)	145,676	82,735	211,691	N/A	440,101	7,782	144,568	9,167	5,162	166,679
(87)	**TARIFFED TRANSPORTATION RATES (¢/th)**	**5.448**	**3.084**	**3.084**	**N/A**	**3.867**	**2.949**	**2.237**	**2.761**	**2.495**	**2.307**
(88)	**Noncore ITCS Rate (¢/th)**	0.793	0.793	0.793	N/A	0.793	0.789	0.789	0.789	0.789	0.789

TABLE 13: DGN & SUMMARY N/C REVENUE ALLOCATION

SOUTHERN CALIFORNIA GAS COMPANY

2000 Biennial Cost Allocation Proceeding

LRMC COST ALLOCATION (M$): MARGINAL COST REVENUE

LINE #	MARGINAL COST COMPONENTS	DGN	UNBUNDLED NONCORE STORAGE	NONCORE TOTAL	UNALLOCATED COSTS TO NSBA	TOTAL
		(b)	(e)	(f)	(g)	(h)
	CUSTOMER RELATED					
(1)	NUMBER OF CUSTOMERS	1	N/A	1,472		4,898,330
(2)	MARGINAL CUSTOMER COST	22.03411	N/A			
(3)	MARGINAL CUSTOMER COST REVENUE	22	0	8,533		356,752
	COMMON DISTRIBUTION - MEDIUM PRESSURE					
(4)	MEDIUM PRESSURE PEAK DAY DEMAND (MMCFD)	0	N/A	171		3,148
(5)	MARGINAL DISTRIBUTION COST	82.7713	N/A			
(6)	MARGINAL DISTRIBUTION COST REVENUE	0	N/A	14,163		260,532
	COMMON DISTRIBUTION - HIGH PRESSURE					
(7)	HIGH PRESSURE PEAK MONTH DEMAND (MMCF)	0	N/A	15,139		66,311
(8)	MARGINAL DISTRIBUTION COST	0.6910	N/A			
(9)	MARGINAL DISTRIBUTION COST REVENUE	0	N/A	10,462		45,823
(10)	TOTAL COMMON DISTRIBUTION COST REVENUE	0	N/A	24,625		306,355
	TRANSMISSION					
(11)	COLD YEAR THROUGHPUT (MDTH)	3,690	N/A	665,265		1,044,284
(12)	MARGINAL TRANSMISSION COST	0.0653	N/A			
(13)	TOTAL TRANSMISSION COST REVENUE	241	N/A	43,421		68,160

TABLE 13: DGN & SUMMARY N/C REVENUE ALLOCATION
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SOUTHERN CALIFORNIA GAS COMPANY
2000 Biennial Cost Allocation Proceeding

LRMC COST ALLOCATION (M$): MARGINAL COST REVENUE

LINE #	MARGINAL COST COMPONENTS	DGN	UNBUNDLED NONCORE STORAGE	NONCORE TOTAL	UNALLOCATED COSTS TO NSBA	TOTAL
		(b)	(e)	(f)	(g)	(h)
	STORAGE					
	INVENTORY:					
(14)	INVENTORY RESERVATION (MMCF)	0	30,271	30,271		100,271
(15)	MARGINAL INVENTORY COST	0.1972	0.1972			
(16)	MARGINAL INVENTORY COST REVENUE	0	5,970	5,970		19,775
	INJECTION CAPACITY:					
(17)	INJECTION RESERVATION (MMCFD)	0	121	121		448
(18)	MARGINAL INJECTION COST	18.611	18.611			
(19)	MARGINAL INJECTION CAPACITY COST REVENUE	0	2,252	2,252		8,340
	VARIABLE INJECTION COST:					
(20)	INJECTIONS (MDTH)	0	30,755	30,755		101,875
(21)	VARIABLE O&M COST	0.012	0.012			
(22)	TOTAL VARIABLE INJECTION COST REVENUE	0	358	358		1,185
	WITHDRAWAL CAPACITY:	0	0	0		0
(23)	WITHDRAWAL RESERVATION (MMCFD)	0	935	935		2,870
(24)	MARGINAL WITHDRAWAL COST	10.689	10.689			
(25)	MARGINAL WITHDRAWAL CAP. COST REVENUE	0	9,995	9,995		30,679
	VARIABLE WITHDRAWAL COST:					
(26)	WITHDRAWALS (MDTH)	0	30,755	30,755		101,875
(27)	VARIABLE O&M COST	0.016	0.016			
(28)	TOTAL VARIABLE WITHDRAWAL COST REVENUE	0	499	499		1,650
(29)	**SUBTOTAL - SEASONAL STORAGE**	0	19,074	19,074		61,628
(30)	MARGINAL LOAD BALANCING COST REVENUE	42	N/A	10,276		10,751
(31)	COMPANY USE GAS: TRANSMISSION	39	N/A	6,993		10,606
(32)	**SYSTEM MARGINAL COST REVENUE**	**344**	**19,074**	**112,922**		**814,253**
(33)	**SCALED LRMC REVENUE**	**575**	**20,747**	**187,910**	**11,187**	**1,373,635**
(34a)	MARKETING(excluding DSM)	60	148	5,434		24,137
(34b)	SDG&E Moreno Credit	0	N/A	(519)		-
(35)	**MARGINAL COST REVENUE W/MKTG & ARCO**	**636**	**20,895**	**192,825**	**11,187**	**1,397,772**
(36)	UNCOLLECTIBLES	-	105	743		6,726
(37)	**TOTAL ALLOCATED MARGIN (M$)**	**636**	**21,000**	**193,568**	**11,187**	**1,404,498**
(38)	**TOTAL ALLOCATED MARGIN (¢/th)**	1.746	-	2.939		-
(39)	**AVERAGE YEAR THROUGHPUT, MDth**	3,642	N/A	658,693		998,566

TABLE 13: DGN & SUMMARY N/C REVENUE ALLOCATION

SOUTHERN CALIFORNIA GAS COMPANY

2000 Biennial Cost Allocation Proceeding

OTHER OPERATING COST AND TRANSITION COST ALLOCATION (M$)

OTHER COST COMPONENTS

Line	Forecast Period Costs	DGN Cost (b)	Unbundled Noncore Storage (e)	Total Noncore Cost (f)	UNALLOCATED Costs to NSBA (g)	Total System Cost (h)
	TRANSPORTATION REVENUE REQ.					
(39)	Subtotal - Margin - Base	636	21,000	193,568	11,187	1,404,498
	Other Operating Costs and Revenues					
(40)	Exchange Revenues & Interutility Transactions	1	N/A	191		308
(40b)	Schedule IB Service Revenue Credit	-	N/A	-		-
(41)	Core Brokerage Fee Adjustment	N/A	N/A	N/A		(6,508)
(42)	Noncore Brokerage Fee Adjustment	(0)	N/A	(83)		(83)
(43a)	Marketing Exclusions: DSM & DAP	-	N/A	100		46,802
(43b)	RD&D "Common Good"	0	N/A	57		510
(44)	Fuel Cell Equipment Revenues	(0)	N/A	(43)		(389)
(45)	Company Use Gas: Storage	10	N/A	1,824		5,317
(46)	Other Company Use Gas	3	N/A	532		806
(47)	Unaccounted For Gas	18	N/A	9,130		32,775
(48)	Carrying Cost Storage Inv.: Load Balancing	1	N/A	88		88
(49)	Well Incidents & Surface Leaks	0	-	8		159
(50)	Subtotal Other Operating Costs and Revenues	32	-	11,802	-	79,786
	Transition Costs					
(51)	MPO Transition Cost Adjustment	-	-	-		-
(52)	Pitco/Popco Transition Costs	(89)	-	(14,975)		(23,325)
(53)	Interstate Trans. Cost Surcharge Accunt (ITCS) [1]	287	-	48,336		59,895
(54)	Subtotal Transition Costs	198	N/A	33,360	-	36,570

[1] Average Year Throughput, Core 10% of PL Demand Cap

TABLE 13: DGN & SUMMARY N/C REVENUE ALLOCATION

SOUTHERN CALIFORNIA GAS COMPANY

2000 Biennial Cost Allocation Proceeding

BALANCING, TRACKING AND MEMORANDUM ACCOUNTS ALLOCATION (M$)

OTHER COST COMPONENTS

Line	Forecast Period Costs	DGN Cost (b)	Unbundled Noncore Storage (e)	Total Noncore Cost (f)	UNALLOCATED Costs to NSBA (g)	Total System Cost (h)
	Balancing, Tracking & Memorandum Accounts:					
(55)	Pitas Point F&U Account (PPF&UA)	(0)	N/A	(23)		(36)
(56)	NGV Account (NGVA)	40	N/A	5,024		8,689
	Noncore Storage Balancing Account (NSBA)					
(57)	Subscribed Storage Revenue Account	4	N/A	636		636
(58)	Storage Transition and Bypass Subaccount	(10)	N/A	(1,611)		(2,509)
(59)	Zone Rate Credit Limitation Memo Acct(ZRCLMA)	(1)	N/A	(164)		(1,472)
(60)	N/C Brokerage Fee Balancing Account (BFBA)	5	N/A	885		885
(61)	Interim Zone Rate Credit Account (IZRCA)	-	N/A	-		-
(62)	Hazardous Substan. Cost Recov. Acct (HSCRA)	35	N/A	5,843		9,101
(63)	Conservation Expense Account (CEA)	-	N/A	-		-
(64)	R D & D Expense Account (RDDEA)	(4)	N/A	(904)		(8,132)
(65)	Core Fixed Cost Account (CFCA)	N/A	N/A	-		(132,043)
(66)	Economic Practicality Shortfall Memo. Acct (EPSMA)	N/A	N/A	(1,639)		(1,639)
(67)	Enhanced Oil Recovery Account-Core(EORA)	N/A	N/A	-		14,140
(68)	Enhanced Oil Recovery Account-N/C (EORA)	6	N/A	1,441		1,441
(69)	Minimum Purchase Obligation (MPO)	20	N/A	3,420		3,420
(70)	Pipeline Demand Charges (PDC)	(0)	N/A	(2)		(2)
(71)	Carrying Cost of Storage (CCS)	-	N/A	51		51
(72)	Take-or-Pay (TOP)	(0)	N/A	(0)		(0)
(73)	Non-Core Fixed Cost Account (NFCA)	14	N/A	2,335		2,335
(74a)	Non-Core Cost/Revenue Memo Acct(NCRMA)	-	N/A	-		-
(74b)	Catastrophic Event Memorandum Account(CEMA)	-	N/A	-		-
(74bb)	CEMA Double Refund Tracking Acct (CEMA-DRT)	-	N/A	-		-
(74bbb)	PBOPS	(4)	N/A	(988)		(8,887)
(74c)	Intervenor Compensation	2	N/A	389		607
(75a)	Auditing Expense Account (AEA)	-	N/A	-		-
(75c)	Research Royalty Memorandum Account (RRMA)	(0)	N/A	(31)		(277)
(75d)	Environmental Fee Account (EFA)	-	N/A	-		-
(75e)	Affiliate Transaction Tracking Account (AFTA)	(0)	N/A	(12)		(111)
(75f)	Fuel Cell Proceeds Memorandum Acct (FCPMA)	-	N/A	-		-
(75)	Subtotal Balancing and Tracking Accounts	108	-	14,650	-	(113,803)
(76)	**Subtotal-Transportation Revenue Requirement**	974	21,000	253,380	11,187	1,407,051
(77)	Subtotal- Transportation Revenue Requirement (¢/th)	2.675	-	4.151		14.806

TABLE 13: DGN & SUMMARY N/C REVENUE ALLOCATION

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SOUTHERN CALIFORNIA GAS COMPANY

2000 Biennial Cost Allocation Proceeding

SUMMARY TRANSPORTATION COST ALLOCATION (M$)

Line	OTHER COST COMPONENTS Forecast Period Costs	DGN Cost (b)	Unbundled Noncore Storage (e)	Total Noncore Cost (f)	UNALLOCATED Costs to NSBA (g)	System (h)
(78)	**Subtotal-Transportation Revenue Requirement**	**974**	**21,000**	**253,380**	**11,187**	**1,407,051**
(79)	Pipeline Demand Charges-EP&TW Trad-Core	-	-	-		118,936
(80)	UEG/Cogeneration Parity Adjustment	0	0	(0)		(0)
(81)	Gas Engine Rate Cap Adjustment	0	0	0		0
(82)	**TOTAL TRANS. REVENUE REQUIREMENT**	**974**	**21,000**	**253,380**	**11,187**	**1,525,987**
	Tariffed Rates					
(83)	Total Transportation Costs (Line 46) Less: EOR	974	21,000	230,604	11,187	1,503,210
(84)	Core Averaging: @ 25%	-	-	-		-
(85)	**TOTAL TRANS. REV. REQ. w/o EOR**	**974**	**21,000**	**230,604**	**11,187**	**1,503,210**
(86)	Average Year Throughput (MDth)	3,642	N/A	610,423		950,295
(87)	**TARIFFED TRANSPORTATION RATES (¢/th)**	**2.675**	**N/A**	**3.778**		**15.818**
(88)	**Noncore ITCS Rate (¢/th)**	0.789	N/A	0.792		

TABLE 14

CORE COMMERCIAL/INDUSTRIAL SEGMENTATION COST ALLOCATION (G-10/G-20)

SOUTHERN CALIFORNIA GAS COMPANY
2000 Biennial Cost Allocation Proceeding

Line		G-10 Band 1 0-3 Mth	G-10 Band 2 3-50 Mth	G-10 Band 3 >50 Mth	G-10 Total	G-20 Band 4 Over 250 Mth	Core Commercial/ Industrial Total
1	COST PER CUSTOMER, $	154.15	475.58	779.79	229.58	1,087.67	229.98
2	CUSTOMER COSTS, M$	23,949	20,405	1,650	46,004	103	46,107
3	C/TH	25.80	4.32	0.74	5.84	0.22	5.52
4	MEDIUM PRESSURE DIST COSTS, M$	7,016	22,640	9,638	39,294	1,210	40,503
5	¢/TH	7.56	4.79	4.34	4.99	2.58	4.85
6	HIGH PRESSURE DISTRIBUTION COSTS, M$	1,183	3,819	1,626	6,628	300	6,928
7	¢/TH	1.28	0.81	0.73	0.84	0.64	0.83
8	TOTAL TRANSMISSION COSTS, M$	651	3,272	1,536	5,459	313	5,773
9	¢/TH	0.70	0.69	0.69	0.69	0.67	0.69
10	TOTAL LOAD BALANCING COST, M$	13	66	31	110	7	117
11	¢/TH	0.01	0.01	0.01	0.01	0.01	0.01
12	TOTAL SEASONAL STORAGE COSTS, M$	1,345	3,618	1,461	6,424	312	6,735
13a	¢/TH	1.45	0.77	0.66	0.82	0.67	0.81
13b	TRANSMISSION COMPANY USE COSTS, M$	99	502	236	837	50	887
13c	¢/TH	0.11	0.11	0.11	0.11	0.11	0.11
14	MARGINAL COST REVENUES, M$	34,256	54,322	16,178	104,756	2,295	107,050
15	SCALING	23,114	36,652	10,916	70,682	1,548	72,230
15a	MARKETING	1,231	2,074	1,024	4,330	135	4,465
15b	ARCO						
	SDG&E MORENO CREDIT	25	40	12	78	2	79
15c	UNCOLLECTIBLES	294	467	141	901	20	921
16	TOTAL ALLOCATED MARGIN, M$	58,920	93,555	28,271	180,746	4,000	184,746
17	CORE AVERAGING COSTS	0	16,204	7,621	23,825	1,606	25,431
18	OTHER REVENUE REQUIREMENTS, M$	1,627	8,285	3,896	13,808	(114)	13,693
19	TOTAL NON MARGIN REVENUE REQUIREMEN	1,627	24,489	11,517	37,633	1,492	39,125
20	TOTAL TARIFFED REVENUE REQUIREMENTS, M	60,547	118,044	39,788	218,379	5,492	223,870
21	Average Year Throughput, Mth	92,818	472,668	222,294	787,780	46,855	834,635
22	AVERAGE TRANSPORTATION RATE, ¢/th	65.232	24.974	17.899	27.721	11.721	26.823
23	TOTAL BUNDLED COST OF SERVICE, ¢/th	65.515	25.258	18.183	28.005	12.005	27.106

TABLE 15

NONCORE COMMERCIAL/INDUSTRIAL MARKET SEGMENTATION BY SERVICE LEVEL (1999 $s)

SOUTHERN CALIFORNIA GAS COMPANY
2000 Biennial Cost Allocation Proceeding

	DISTRIBUTION	TRANSMISSION	TOTAL
CUSTOMER-RELATED MCR, M$	5,226.0	102.9	5,328.9
C/TH	0.45	0.03	0.37
MEDIUM PRESSURE DISTRIBUTION MCR, M$	12,598.4	0.0	12,598.4
C/TH	1.09	0.00	0.86
HIGH PRESSURE DISTRIBUTION MCR, M$	7,212.6	0.0	7,212.6
C/TH	0.62	0.00	0.50
TRANSMISSION MCR, M$	7,608.2	1,979.2	9,587.4
C/TH	0.66	0.66	0.66
LOAD BALANCING MCR, M$	1,578.5	410.6	1,989.2
C/TH	0.14	0.14	0.14
COMPANY USE TRANSMISSION	1,228.9	319.7	1,548.6
MARGINAL COST REVENUE, M$	**35,452.6**	**2,812.5**	**38,265.0**
SCALING	23,904.1	1,896.3	25,800.4
MARKETING	2,949.9	58.1	3,008.0
SDG&E Moreno Credit	26.2	2.1	28.3
Subtotal	62,332.8	4,769.0	67,101.7
UNCOLLECTIBLES M$	312.4	23.9	336.3
TOTAL ALLOCATED MARGIN M$	62,645.2	4,792.9	67,438.1
OTHER REVENUE REQUIREMENTS [1]	294.3	76.6	370.8
TOTAL TRANSPORTATION REVENUE REQUIREMENT	**62,939.5**	**4,869.4**	**67,808.9**
Average Year Throughput at Tariff, Mth	1,156,023	300,734	1,456,757
AVERAGE TRANSPORTATION RATES (c/therm)	5.444	1.619	4.655

[1] Exclusive of ITCS costs

TABLE 16
Page 1

Customer Marginal Costs

SOUTHERN CALIFORNIA GAS COMPANY
2000 Biennial Cost Allocation Proceeding

MARGINAL COSTS	Units	1996 BCAP Costs [1]	2000 BCAP Costs
Core			
Residential	M$/Customer	0.13575	0.06397
Small Core Com/Ind - G-10	M$/Customer	0.43699	0.22958
Large Core Com/Ind - G20	M$/Customer	3.11094	1.08767
Gas Air Conditioning	M$/Customer	2.50193	1.95658
Gas Engines	M$/Customer	1.82568	2.41203
Noncore - Retail			
Com/Ind - G30	M$/Customer	8.14700	4.58469
Cogeneration - G50 Total	M$/Customer	7.40855	5.91272
UEG - G60 Total	M$/Customer	601.80990	40.67044 [2]
EOR - G40	M$/Customer	28.22059	11.00490
Noncore - Wholesale			
Long Beach - G70	M$/Customer	400.95058	71.36107
SDG&E - G80	M$/Customer	1,159.58512	99.43634
Southwest Gas - G90	M$/Customer	93.63426	43.28432
Vernon	M$/Customer	NA	23.75486
Noncore - International			
DGN	M$/Customer	NA	22.03411

[1] 1996 BCAP marginal costs are in 1996 dollars, 2000 BCAP marginal costs are in 1999 dollars.

[2] Note: The present customer cost for UEG is based on number of UEG customers (8), the proposed marginal customer cost for UEG are based on number of plants (23).

TABLE 16
Page 2

Non-Customer Marginal Costs

SOUTHERN CALIFORNIA GAS COMPANY
2000 Biennial Cost Allocation Proceeding

MARGINAL COSTS	Units	1996 BCAP Costs [1]	2000 BCAP Costs
Common Distribution			
Medium Pressure	$/Mcfd of Peak Day Demand	96.85940	82.77130
High Pressure	$/Mcf of Peak Month Demand	0.53750	0.69103
Transmission			
Base Rate Marginal Cost	$/Dth of Cold Year Throughput	0.09175	0.06527
Storage			
Inventory:			
Marginal Cost	$/Mcf of Inventory Reservation	0.18323	0.19722
Injection Capacity:			
Marginal Cost	$/Mcfd of Injection Reservation	21.49898	18.61146
Variable O&M	$/Dth of Injection	0.02890	0.01165
Withdrawal Capacity:			
Marginal Cost	$/Mcfd of W/D Res. PD Demand	13.06699	10.68946
Variable O&M	$/Dth of Withdrawal	0.02244	0.01622

[1] 1996 BCAP marginal costs are in 1996 dollars, 2000 BCAP marginal costs are in 1999 dollars.

TABLE 17
Submeter Avoided Cost Credit

SOUTHERN CALIFORNIA GAS COMPANY
2000 Biennial Cost Allocation Proceeding

	Western Mobilehome Parkowners Association, Exh 52a as filed w/Scaling	
	Avoided Cost Per Subunit	Costs Incurred For Master Meter
I. Capital Cost		
Meter	$18.66	$39.02
Service Line	$46.31	$53.65
Mains	$22.41	$22.41
Total	$87.38	$115.08
II. O&M Cost		
Meter O&M	$1.65	$3.43
Service Line O&M	$7.64	$8.85
Customer Services O&M	$12.53	$24.13
Customer Accounts O&M	$19.40	$27.03
A&G Loading	$12.62	$19.42
General Plant Loading	$5.92	$9.11
M&S Costs	$0.13	$0.20
Total	$59.89	$92.16
II.a. SCALING	19.64%	19.64%
III. Avoided/Incurred Customer Related Cost	$176.21	$247.95
IV. Avoided Cost - Monthly Basis	$14.68	$20.66
V. Average Number of Subunits Per Master Meter Account		67.03
VI. Incurred Cost Per Living Unit for Master Meter		$0.31
VII. Net Avoided Cost - Monthly	$14.37	

TABLE 18
Page 1

COMPARISON RATE TABLE
CORE PROCUREMENT CUSTOMER: TRANSPORTATION RATES
SOUTHERN CALIFORNIA GAS COMPANY

2000 Biennial Cost Allocation Proceeding

Core Customer Class	Rates in Effect 10/07/98	Rates In Effect [2] 1/01/2000	BCAP Authorized Rates
	($/th)	($/th)	($/th)
(A)	(B)	(C)	(D)
RESIDENTIAL			
Customer Charge			
Single Family			$5.00
Multi-Family Family			$5.00
Small Master Metered			$5.00
Tier I Volumetric			0.24405
Tier II Volumetric			0.42389
Subtotal Residential	0.48076	0.45647	0.41052
LARGE MASTER METERED			
Customer Charge			
Tier I Volumetric			
Tier II Volumetric			
Subtotal Residential	0.33609	0.31198	0.30033
CORE COMMERCIAL & INDUSTRIAL	Small (G-10)	Small (G-10)	Combined (G-10/G-20) [4]
Customer Charge	$15.00	$15.00	$10.00/15.00
Tier I Volumetric [1]	0.51531	0.50960	0.38280
Tier II Volumetric	0.29146	0.26313	0.22955
Tier III Volumetric	0.13614	0.10908	0.10006
Subtotal G-10	0.35814	0.33462	0.27333
LARGE CORE COMMERCIAL & INDUSTRIAL (G-20)			
Customer Charge	$350.00	$350.00	NA
Tier I Volumetric [3]	0.26449	0.21290	NA
Tier II Volumetric	0.13614	0.10908	NA
Subtotal G-20	0.16888	0.13718	NA
NON-RES GAS A/C			
Customer Charge	$150.00	$150.00	$150.00
Volumetric	0.17325	0.11924	0.08551
Subtotal Non-Res Gas A/C	0.20025	0.14624	0.11251
GAS ENGINES			
Customer Charge	$50.00	$50.00	$50.00
Volumetric	0.18833	0.13761	0.18057
Subtotal Gas Engines	0.21444	0.16371	0.20668

[1] Tier I quantity equals first 250 therms per month in December - March, and first 100 therms per month in April - November.
Tier II quantity is from Tier I to 4,167 therms. The customer charge is $10 for customers < 1000 therms/year & $15 for all other customers.

[2] 1/01/2000 rates for residential and core commercial & industrial are based on proposed total number of customers, proposed demand forecasts, D.97-04-082 residential baseline-Tier II factors and present rates for both residential and both small & large core commercial & industrial.

[3] Tier 1 quantity is first 4167 therms.

[4] Small and Large Core Commercial & Industrial Merged into single Commercial & Industrial Rate.

NOTE: Bundled Procurement Transportation Rates rates exclude a brokerage fee of 0.201 cents/therm, and the Core Portfolio WACOG. The current core WACOG including brokerage fee is 17.602 ¢/therm. The core WACOG is updated monthly, and along with the brokerage fee is additive to all bundled Procurement Transportation Rates.

TABLE 18
Page 2

COMPARISON RATE TABLE
CORE TRANSPORTATION CUSTOMER: TRANSPORTATION RATES
SOUTHERN CALIFORNIA GAS COMPANY

2000 Biennial Cost Allocation Proceeding

Core Customer Class (A)	Rates in Effect 10/07/98 ($/th) (B)	Rates In Effect [2] 1/01/2000 ($/th) (C)	BCAP Authorized Rates ($/th) (D)
RESIDENTIAL			
Customer Charge			
Single Family			$5.00
Multi-Family Family			$5.00
Small Master Metered			$5.00
Tier I Volumetric			0.24121
Tier II Volumetric			0.42105
Subtotal Residential	0.47794	0.45365	0.40768
LARGE MASTER METERED			
Customer Charge			
Tier I Volumetric			
Tier II Volumetric			
Subtotal Residential	0.33327	0.30916	0.29749
CORE COMMERCIAL & INDUSTRIAL	Small (G-10)	Small (G-10)	Combined (G-10/G-20) [4]
Customer Charge	$15.00	$15.00	$10.00/15.00
Tier I Volumetric [1]	0.51249	0.50678	0.37996
Tier II Volumetric	0.28864	0.26031	0.22671
Tier III Volumetric	0.13332	0.10626	0.09723
Subtotal G-10	0.35532	0.33180	0.25646
LARGE CORE COMMERCIAL & INDUSTRIAL (G-20)			
Customer Charge	$350.00	$350.00	NA
Tier I Volumetric [3]	0.26167	0.21008	NA
Tier II Volumetric	0.13332	0.10626	NA
Subtotal G-20	0.16606	0.13436	NA
NON-RES GAS A/C			
Customer Charge	$150.00	$150.00	$150.00
Volumetric	0.17043	0.11642	0.08267
Subtotal Non-Res Gas A/C	0.19743	0.14342	0.10967
GAS ENGINES			
Customer Charge	$50.00	$50.00	$50.00
Volumetric	0.18551	0.13479	0.17773
Subtotal Gas Engines	0.21162	0.16090	0.20384

[1] Tier I quantity equals first 250 therms per month in December - March, and first 100 therms per month in April - November.
Tier II quantity is from Tier I to 4,167 therms. The customer charge is $10 for customers < 1000 therms/year & $15 for all other customers.

[2] 1/01/2000 rates for residential and core commercial & industrial are based on proposed total number of customers, proposed demand forecasts, D.97-04-082 residential baseline-Tier II factors and present rates for both residential and both small & large core commercial & industrial.

[3] Tier 1 quantity is first 4167 therms.

[4] Small and Large Core Commercial & Industrial Merged into single Commercial & Industrial Rate.

NOTE: Bundled Procurement Transportation Rates rates exclude a brokerage fee of 0.201 cents/therm, and the Core Portfolio WACOG. The current core WACOG including brokerage fee is 17.602 ¢/therm. The core WACOG is updated monthly, and along with the brokerage fee is additive to all bundled Procurement Transportation Rates.

TABLE 18
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COMPARISON RATE TABLE
NONCORE TRANSPORTATION RATES

SOUTHERN CALIFORNIA GAS COMPANY

2000 Biennial Cost Allocation Proceeding

Noncore Customer Class	Rates In Effect 10/07/98 ($/th)	Rates In Effect [2] 1/01/2000 ($/th)	BCAP Authorized Rates ($/th)
(A)	(B)	(C)	(D)
NONCORE			
COMMERCIAL & INDUSTRIAL			
VOLUMETRIC RATE	0.05258	0.04651	0.04655 [3]
ITCS	0.01424	0.01527	0.00793
TOTAL	0.06682	0.06178	0.05448
CARE SURCHARGE	0.00994	0.00721	0.00121
ELECTRIC GENERATION (EG) [1]			
VOLUMETRIC RATE	0.03275	0.02584	0.02291 [4]
ITCS	0.01424	0.01527	0.00793
SUBTOTAL	0.04699	0.04111	0.03084
COMMON EG RATE ADJ.			0.00305
TOTAL			0.03389
WHOLESALE			
LONG BEACH			
VOLUMETRIC RATE	0.03679	0.03036	0.02160
ITCS	0.01417	0.01520	0.00789
TOTAL	0.05096	0.04556	0.02949
SDG&E			
VOLUMETRIC RATE	0.02686	0.02018	0.01448
ITCS	0.01417	0.01520	0.00789
TOTAL	0.04103	0.03538	0.02237
SOUTHWEST GAS			
VOLUMETRIC RATE	0.03040	0.02367	0.01972
ITCS	0.01417	0.01520	0.00789
TOTAL	0.04457	0.03887	0.02761
VERNON			
VOLUMETRIC RATE	N/A	N/A	0.01706
ITCS	N/A	N/A	0.00789
TOTAL	N/A	N/A	0.02495
INTERNATIONAL			
DGN			
VOLUMETRIC RATE	N/A	N/A	0.01886
ITCS	N/A	N/A	0.00789
VOLUMETRIC RATE	N/A	N/A	0.02675
BROKERAGE FEES	0.00266	0.00266	0.00266

[1] Includes all electric generation including traditional Utility Electric Generation Municipal and all Qualifying Facilities.

[2] 1/01/2000 rates have included wholesale storage costs in Unbundled Storage.

[3] See Table 5 for BCAP adopted noncore commercial and industrial segmented rate design.

[4] See Table 8 for BCAP adopted EG segmented rate design.

TABLE 19

SOUTHERN CALIFORNIA GAS COMPANY
2000 Biennial Cost Allocation Proceeding

TYPICAL WINTER MONTHLY BILLS
Residential Customers

Line # (A)	Monthly Energy Usage (B) therms	Bill At 1/01/2000 Rates (C) $	Bill At BCAP Rates (D) $	Change (E) $	% Change (F)	Number of Customers (G)	Percent of Total (H)
1	0	$ 5.00	$ 5.00	$ -	0.0%	3,723	0.12%
2	5	$ 7.70	$ 7.42	(0.27)	-3.6%	14,406	0.47%
3	10	$ 10.39	$ 9.84	(0.55)	-5.3%	22,769	0.74%
4	15	$ 13.09	$ 12.26	(0.82)	-6.3%	26,783	0.87%
5	20	$ 15.78	$ 14.68	(1.10)	-7.0%	43,605	1.41%
6	25	$ 18.48	$ 17.11	(1.37)	-7.4%	62,775	2.03%
7	30	$ 21.17	$ 19.53	(1.65)	-7.8%	80,115	2.59%
8	35	$ 23.87	$ 21.95	(1.92)	-8.0%	86,954	2.81%
9	40	$ 26.56	$ 24.37	(2.19)	-8.3%	102,554	3.32%
10	45	$ 29.26	$ 26.79	(2.47)	-8.4%	88,846	2.87%
11	50	$ 31.95	$ 29.39	(2.56)	-8.0%	120,403	3.89%
12	55	$ 35.47	$ 32.71	(2.76)	-7.8%	130,473	4.22%
13	60	$ 38.99	$ 36.03	(2.96)	-7.6%	136,948	4.43%
14	65	$ 42.51	$ 39.35	(3.16)	-7.4%	138,869	4.49%
15	70	$ 46.03	$ 42.67	(3.36)	-7.3%	148,911	4.82%
16	75	$ 49.55	$ 45.99	(3.56)	-7.2%	121,407	3.93%
17	80	$ 53.07	$ 49.31	(3.76)	-7.1%	148,362	4.80%
18	85	$ 56.59	$ 52.63	(3.96)	-7.0%	146,518	4.74%
19	90	$ 60.11	$ 55.95	(4.16)	-6.9%	142,937	4.62%
20	95	$ 63.63	$ 59.27	(4.36)	-6.8%	131,392	4.25%
21	100	$ 67.15	$ 62.59	(4.56)	-6.8%	122,780	3.97%
22	125	$ 84.75	$ 79.19	(5.56)	-6.6%	450,756	14.58%
23	150	$ 102.35	$ 95.80	(6.55)	-6.4%	264,092	8.54%
24	200	$ 137.55	$ 129.00	(8.55)	-6.2%	226,256	7.32%
25	300	$ 207.94	$ 195.40	(12.54)	-6.0%	102,893	3.33%
26	400	$ 278.34	$ 261.81	(16.53)	-5.9%	16,645	0.54%
27	500	$ 348.73	$ 328.21	(20.52)	-5.9%	4,752	0.15%
28	1000	$ 700.71	$ 660.24	(40.48)	-5.8%	3,951	0.13%
29	2000	$ 1,404.67	$ 1,324.28	(80.38)	-5.7%	688	0.02%
30	>2000					95	0.00%
31	Total					3,091,658	100.00%

NOTE: Procurement cost is updated monthly. Therefore the procurement cost used in bills at present and BCAP Authorized rates is the average rate included in this BCAP of 23.819 ¢/therm. Used 31 Day Month.

TABLE 20

CARE SURCHARGE

SOUTHERN CALIFORNIA GAS COMPANY
2000 Biennial Cost Allocation Proceeding

Line #		M$
1	Adopted CARE Program Costs (M$)	23,242
2	CARE SEC CREDIT (M$)	1,908
3	CARE ADMINISTRATIVE COSTS (M$)	2,050
4	CARE BALANCING ACCOUNT (M$)	(21,627)
5	TOTAL CARE COST (M$)	5,574
6	CARE NONEXEMPT VOLUMES (Mth) (Core+Noncore Commercial & Industrial - CARE Participation)	4,614,042
7	CARE SURCHARGE ($/th)	0.00121

(END OF APPENDIX D)

APPENDIX E

TABLE 1

SAN DIEGO GAS & ELECTRIC
2000 Biennial Cost Allocation Proceeding

SUMMARY OF MARGINAL COST REVENUES

Line	Description	CORE					NONCORE				TOTAL	Line
		Resid	GN-1	NGV	GN-2	Total	GTNC	COGEN	GTUEG	Total	SYSTEM	
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
	Customer Marginal Costs											
1	$/Customer/Year	$67	$88	$542	$3,436	$68	$4,499	$4,678	$26,756	$6,034	$69	1
2	Number of Customers	711,899	27,449	302	17	739,667	90	51	10	151	739,818	2
3	Customer Marginal Costs	$47,740	$2,411	$164	$58	$50,373	$405	$239	$268	$911	$51,285	3
	Distribution Marginal Costs											
4	Medium Pressure Cost	$103.33	$103.33	$103.33	$103.33		$103.33	$103.33	$103.33			4
5	NPD - Medium Press.	259,824	56,596	1,269	1,840		8,908	2,346	0			5
6	Marginal Costs - MPS	$26,848	$5,848	$131	$190	$33,017	$920	$242	$0	$1,163	$34,180	6
7	High Pressure Cost	$35.17	$35.17	$35.17	$35.17		$35.17	$35.17	$35.17			7
8	NPD - High Pressure	259,824	56,596	1,269	2,088		19,281	26,139	141			8
9	Marginal Costs - HPS	$9,138	$1,990	$45	$73	$11,247	$678	$919	$5	$1,602	$12,849	9
	Transmission Marginal Costs											
10	Cold-Yr Pk-Month	51,364	14,597	331	644		7,309	14,401	38,350			10
11	Conversion Factor	10.10	10.10	10.10	10.10		10.10	10.10	10.10			11
12	Cold-Yr Pk-Month	5,086	1,445	33	64		724	1,426	3,797			12
13	Fixed Trans. Cost $/Mcfd	$1.45	$1.45	$1.45	$1.45		$1.45	$1.45	$1.45			13
14	Marginal Cost - Fixed TLS	$7,392	$2,101	$48	$93	$9,633	$1,052	$2,073	$5,519	$8,644	$18,277	14
							0.00%	0.00%	0.00%			
15	Fuel Trans. Cost $/mther	$1.082	$1.082	$1.082	$1.082		$1.082	$1.082	$1.082			15
16	Adj. Avg-Yr Delv	326,207	123,612	4,030	6,182		86,211	168,926	729,000			16
17	Marginal Cost - Fuel TLS	$353	$134	$4	$7	$498	$93	$183	$789	$1,065	$1,563	17
18	Marginal Cost - TLS	$7,745	$2,235	$52	$99	$10,131	$1,145	$2,255	$6,308	$9,709	$19,840	18
	Marginal Cost Summary											
19	Customer Marginal Costs	$47,740	$2,411	$164	$58	$50,373	$405	$239	$268	$911	$51,285	19
20	Marginal Costs - MPS	$26,848	$5,848	$131	$190	$33,017	$920	$242	$0	$1,163	$34,180	20
21	Marginal Costs - HPS	$9,138	$1,990	$45	$73	$11,247	$678	$919	$5	$1,602	$12,849	21
22	Marginal Cost - TLS	$7,745	$2,235	$52	$99	$10,131	$1,145	$2,255	$6,308	$9,709	$19,840	22
23	Total Marginal Costs	$91,471	$12,485	$391	$421	$104,768	$3,149	$3,656	$6,581	$13,385	$118,153	23
24	EPMC Allocation Factor	77.42%	10.57%	0.33%	0.36%	88.67%	2.66%	3.09%	5.57%	11.33%	100.00%	24
25	IB Class Rate Credit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	25
		Allocated to All Customers on an EPMC basis.										
26	Global Settlement Prepayment Bal Acct - Core Portion	($4,453)	($1,518)	($55)	($85)	($6,112)	$0	$0	$0	$0	($6,112)	26

TABLE 2

SAN DIEGO GAS & ELECTRIC
2000 Biennial Cost Allocation Proceeding
Reflects Margin Costs as of 1/1/2000

SUMMARY OF COST ALLOCATION

(thousands of dollars)

Line	Description	CORE					NONCORE				TOTAL	Line
		Resid	GN-1	NGV	GN-2	Total	GTNC	COGEN	GTUEG	Total	SYSTEM	
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
	Margin Allocation											
1	Marginal Cost Revenues	$91,471	$12,485	$391	$421	$104,768	$3,149	$3,656	$6,581	$13,385	$118,153	1
2	EPMC Allocator	77.42%	10.57%	0.33%	0.36%	88.67%	2.66%	3.09%	5.57%	11.33%	100.00%	2
3	Margin Allocation	$153,545	$20,957	$657	$707	$175,866	$5,285	$6,136	$11,047	$22,468	$198,335	3
	Non-Margin Allocation											
4	Balancing Accounts	$306	$116	$4	$6	$432	$182	$356	$228	$767	$1,198	4
5	IB Class Credit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	5
6	Global Settlement Credit	($4,453)	($1,518)	($55)	($85)	($6,112)	$0	$0	$0	$0	($6,112)	6
7	SoCalGas Transportation	$7,307	$2,769	$90	$138	$10,304	$1,931	$3,784	$16,328	$22,043	$32,347	7
8	SoCalGas Storage	$3,651	$1,245	$45	$70	$5,011	$136	$57	$0	$194	$5,205	8
9	Other Expense	$1,535	$553	$18	$28	$2,133	$361	$702	$2,975	$4,039	$6,171	9
10	Care Costs	($1,927)	$524	$17	$26	($1,360)	$365	$0	$0	$365	($994)	10
11	Ignitor Adjustment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	11
12	Non-margin Subtotal	$6,418	$3,688	$119	$183	$10,408	$2,976	$4,900	$19,532	$27,408	$37,815	12
	Cost Allocation											
13	Cost-Based Revenue	$159,964	$24,644	$776	$890	$186,274	$8,261	$11,036	$30,579	$49,876	$236,150	13
14	Capping Adjustment	($21,203)	$20,978	$0	$224	($0)	$0	$0	$0	$0	($0)	14
15	Cogen UEG Parity Adjust	$0	$0	$0	$0	$0	$0	($3,207)	$3,207	$0	$0	15
16	Proposed Rate Revenues	$138,761	$45,623	$776	$1,114	$186,274	$8,261	$7,829	$33,786	$49,876	$236,150	16
	Transportation Rate Summary											
17	Proposed Volumes (mtherms)	326,207	123,612	4,030	6,182	460,031	86,211	168,926	729,000	984,137	1,444,168	17
18	**Present Rate Revenues**	**$153,913**	**$46,422**	**$2,739**	**$1,171**	**$204,244**	**$8,535**	**$10,140**	**$40,937**	**$59,612**	**$263,856**	18
19	Present Average Rate	47.183	37.554	67.957	18.935	44.398	9.900	6.003	5.615	6.057	18.270	19
20	Initial Proposed Rate Revenues	$138,761	$45,623	$776	$1,114	$186,274	$8,261	$7,829	$33,786	$49,876	$236,150	20
21	Initial Proposed Average Rate	42.538	36.908	19.256	18.026	40.492	9.582	4.635	4.635	5.068	16.352	21
22	Proposed Average Semprawide Billing Rate for SDG&E							3.635	3.635			22
23	Difference from Initial Proposed Rates							(1.000)	(1.000)			23
24	Revenue Difference							($1,689)	($7,287)	($8,976)	($8,976)	24
25	**Final Proposed Revenues**	**$138,761**	**$45,623**	**$776**	**$1,114**	**$186,274**	**$8,261**	**$6,140**	**$26,499**	**$40,900**	**$227,175**	25
26	Changed Rate Revenue	($15,152)	($799)	($1,963)	($56)	($17,970)	($273)	($4,000)	($14,438)	($18,711)	($36,681)	26
27	Changed Average Rate	(4.645)	(0.646)	(48.701)	(0.909)	(3.906)	(0.317)	(2.368)	(1.980)	(1.901)	(2.540)	27
28	**Percent Change**	**-9.8%**	**-1.7%**	**-71.7%**	**-4.8%**	**-8.8%**	**-3.2%**	**-39.4%**	**-35.3%**	**-31.4%**	**-13.9%**	28
29	Core De-Averaging Amt	$2,356	($2,356)	$1000 per year								29
30	Core De-Averaging Rate	0.722	(1.760)	cents/therm/year								30

Notes Adopted Rate Revenues exclude Miscellaneous Revenues of $4.9 million and brokerage fees of $0.5 million.
The figures prior to the Transportation Rate Summary reflect SDG&E revenues on a "stand alone" basis (i.e., no Semprawide rates).

TABLE 3

SAN DIEGO GAS & ELECTRIC
2000 Biennial Cost Allocation Proceeding
Reflects Margin & Allocated SoCalGas Costs as of 1/1/2000

COMMON EG RATE FOR SDG&E and SOCALGAS

Line			Stand-alone rates SoCalGas	Stand-alone rates SDG&E	Total	Adopted Semprawide Rates	Line
			(A)	(B)	(C)	(D)	
1	Allocated EG Cost	m$	$90,809	$41,615	$132,424		1
2	/ EG Throughput	mdth	294,426	89,793	384,218		2
3	= Average Rate	¢/therm	3.084	4.635	3.447		3
4	Cost Adjustment	m$	$8,976	($8,976)	$0		4
5	Adjusted Costs	m$	$99,785	$32,639	$132,424		5
						class average	
6	**Average EG Rate**	¢/therm	3.389	3.635	3.447	3.447	6

Rate Segmentation

Line			(A)	(B)	(C)	(D)	Line
	For Part A	*>> Annual Usage 0 - 3 million therms <<*				**Part A Rates**	
7	Customers		172	51	223	*customer charge*	7
8	x Customer Charge	$1/mth	$50	$50	$50	$50	8
9	Cust.Charge revenues	m$	$103	$31	$134		9
10	Allocated Charges	m$	$2,888	$5,881	$8,769		10
11	less customer charg	m$	$103	$31	$134		11
12	Volumetric Revenues	m$	$2,785	$5,851	$8,635		12
13	/ Volumes	mdth	4,841	8,377	13,218	*volumetric rate*	13
14	Volumetric Rate	¢/therm	5.753	6.984	6.533	6.533	14
15	Class Average	¢/therm	5.966	7.021	6.634		15
16	**For Part B**	*>> Annual Usage over 3 million therms <<*				**Part B Rates**	
17	Allocated Charges	m$	$87,921	$35,734	$123,655		17
18	/ Volumes	mdth	289,585	81,416	371,001	*volumetric rate*	18
19	Volumetric Rate	¢/therm	3.036	4.389	3.333	3.333	19

Proof of Revenue Recovery

Line			(A)	(B)	(C)	(D)	Line
20	SoCalGas	$/month	$50	172	$103		20
21	0-3 million therms	¢/therm	6.533	4,841	$3,163		21
22	over 3 million therms	¢/therm	3.333	289,585	$96,519		22
23		SCG Total			$99,785	$99,785	23
24	SDG&E	$/month	$50	51	$31		24
25	0-3 million therms	¢/therm	6.533	8,377	$5,473		25
26	over 3 million therms	¢/therm	3.333	81,416	$27,136		26
27		SDGE Total			$32,639	$32,639	27
28	**Sempra EG Totals**		3.447	384,218	$132,424	$132,424	28

Notes: Columns (A) and (B) reflect stand-alone results utilizing this rate design.
Column (C) reflects the the sum of columns (A) and (B) .
Column (D) reflects the final EG rates applicable to both SoCalGas and SDG&E.

TABLE 4
SAN DIEGO GAS & ELECTRIC
2000 Biennial Cost Allocation Proceeding

Summary of Residential Rates

	CUSTOMER GROUP	Units	Rates in effect 1/1/2000	BCAP Authorized Rates	Rate Change	%Change	
		A	B	C	D	E	
1	***Bundled Services*** *1/*						1
2	Regular Baseline **Schedules GR,GM,GS,GT**	¢/therm	67.437	**65.283**	-2.154	-3.2%	2
3	Regular Non-Baseline	¢/therm	88.995	**81.086**	-7.909	-8.9%	3
4	Average Rate *(excluding CARE customers)*	¢/therm	74.789	70.672	-4.116	-5.5%	4
5	NBL/BL Difference	¢/therm	21.558	15.803			5
6	NBL/BL Ratio		1.320	1.242			6
7		*¢/therm*					7
8	*CARE Baseline* *Illustrative 2/* *15.0%*	*¢/therm*	*56.888*	***55.111***	*-1.777*	*-3.1%*	8
9	*CARE Non-Baseline* *Illustrative 2/* *15.0%*	*¢/therm*	*75.212*	***68.543***	*-6.669*	*-8.9%*	9
10	CARE Surcharge	¢/therm	0.510	**0.447**	-0.063		10
11							11
12	GS Unit Discount **Schedule GS**	¢/day	-6.268	**-23.200**	-16.932	270.1%	12
13	GT Unit Discount **Schedule GT**	¢/day	-20.010	**-31.000**	-10.990	54.9%	13
14							14
15	LNG Facility Charge **Schedule GL-1**	$/month	$13.46	**$13.46**	$0.00	0.0%	15
16	LNG Volumetric Surcharge	¢/therm	15.080	**15.080**	0.000	0.0%	16
17	Average Full Service LNG Rate 3/	¢/therm	134.107	130.109	-3.998	-3.0%	17
18							18
19	***Transport-Only*** *(SDG&E + SoCalGas) 4/*						19
20	Regular Baseline **Schedules GTC & GTCA**	¢/therm	41.429	**39.275**	-2.154	-5.2%	20
21	Regular Non-Baseline	¢/therm	62.987	**55.078**	-7.909	-12.6%	21
22	Average Rate *(excluding CARE customers)*	¢/therm	74.789	70.672	-4.116	-5.5%	22
23							23
24	*CARE Baseline* *Illustrative 2/*	*¢/therm*	*30.880*	***29.103***	*-1.777*	*-5.8%*	24
25	*CARE NBL* *Illustrative 2/*	*¢/therm*	*49.204*	***42.535***	*-6.669*	*-13.6%*	25
26							26
27	***SDG&E Transport-Only*** *4,5/*						27
28	Regular Baseline **Schedule GTC-SD**	¢/therm	38.111	**36.921**	-1.190	-3.1%	28
29	Regular Non-Baseline	¢/therm	59.669	**52.724**	-6.945	-11.6%	29
30	Average Rate *(excluding CARE customers)*	¢/therm	71.471	68.318	-3.153	-4.4%	30
31							31
32	*CARE Baseline* *Illustrative 2/*	*¢/therm*	*27.562*	***26.748***	*-0.814*	*-3.0%*	32
33	*CARE NBL* *Illustrative 2/*	*¢/therm*	*45.886*	***40.181***	*-5.705*	*-12.4%*	33
34							34
35	***Other Core Rates***						35
36	Schedule GPC - WACOG annual average 1/	¢/therm	26.008	**26.008**	0.000	0.0%	36
37	CORE ITCS *(embedded in rates)*	¢/therm	1.473	**0.790**	-0.683	-46.4%	37

Notes *1/ Reflects historical annual average procurement rates. Actual tariff rates reflect monthly changing Schedule GPC prices.*
2/ CARE rates are 15% less than regular fully bundled services rates (i.e., net of the CARE surcharge) and change monthly due to monthly changing procurement prices.
3/ Reflects total LNG bill that includes both Schedule GR charges in addition to Schedule GL-1 charges.
4/ Both 1/1/2000 and BCAP authorized rates exclude an amount for Core Interstate Transition Cost Surcharges (CITCS).
5/ These rates reflect a volumetric removal of SCGas costs at a SCG Schedule GT-SD billing basis from bundled transport-only rates.

TABLE 5
SAN DIEGO GAS & ELECTRIC
2000 Biennial Cost Allocation Proceeding

Summary of NGV Rates

	CUSTOMER GROUP		Units	Rates in effect 1/1/2000	BCAP Authorized Rates	Rate Change	%Change	
			A	B	C	D	E	
1	***Bundled Services*** *1/*							1
2	Vehicles	Schedule G-NGV	¢/therm	98.151	**62.652**	-35.499	-36.2%	2
3	Bus Fleets		¢/therm	71.262	**62.652**	-8.610	-12.1%	3
4	Uncompressed Gas		¢/therm	39.910	**33.524**	-6.386	-16.0%	4
5	Co-Funded		¢/therm	69.030	**48.088**	-20.942	-30.3%	5
6								6
7								7
8	***Transport-Only*** ***(SDG&E + SoCalGas)*** *2/*							8
9	Vehicles	Schedule GT-NGV	¢/therm	n/a	**36.644**			9
10	Bus Fleets		¢/therm	n/a	**36.644**			10
11	Uncompressed Gas		¢/therm	13.902	**7.516**	-6.386	-45.9%	11
12	Co-funded		¢/therm	n/a	**22.080**			12
13								13
14								14
15	***SDG&E Transport-Only*** *2,3/*							15
16	Vehicles	Schedule GTC-SD	¢/therm	n/a	**34.290**			16
17	Bus Fleets		¢/therm	n/a	**34.290**			17
18	Uncompressed Gas		¢/therm	10.584	**5.162**	-5.422	-51.2%	18
19	Co-funded		¢/therm	n/a	**19.726**			19
20								20
21	Global Expense Rate		¢/therm	n/a	**n/a**			21

Notes 1/ Reflects historical annual average procurement rates. Actual tariff rates reflect monthly changing Schedule GPC prices.
2/ Both 1/1/2000 and BCAP authorized rates exclude an amount for Core Interstate Transition Cost Surcharges (CITCS).
3/ These rates reflect a volumetric removal of SCGas costs at a SCG Schedule GT-SD billing basis from bundled transport-only rates.

TABLE 6
SAN DIEGO GAS & ELECTRIC
2000 Biennial Cost Allocation Proceeding

Summary of Core Commercial & Industrial Rates
Rates for all Core Commercial Customers

	CUSTOMER GROUP			Units A	Rates in effect 1/1/2000 B	BCAP Authorized Rates C	Rate Change D	%Change E	
1	***Bundled Services*** *1/*		Schedule GN-3						1
1	Service Fees	1,000	therms	$/month	n/a	$5.08			1
2		21,000	therms	$/month	n/a	$10.16			2
3		Over		$/month	n/a	$101.57			3
4									4
5	Volumetric Charges	1,000	therms	¢/therm	n/a	78.157			5
6	Winter	21,000	therms	¢/therm	n/a	46.898			6
7		Over	therms	¢/therm	n/a	40.277			7
8									8
9	Summer	1,000	therms	¢/therm	n/a	67.025			9
10		21,000	therms	¢/therm	n/a	46.293			10
11		Over	therms	¢/therm	n/a	38.227			11
12									12
13	***Transport-Only*** *(SDGE+SCG) 2/*		Schedules GTC & GTCA						13
14	Service Fees	1,000	therms	$/month	n/a	$5.08			14
15		21,000	therms	$/month	n/a	$10.16			15
16		Over		$/month	n/a	$101.57			16
17									17
18	Volumetric Charges	1,000	therms	¢/therm	n/a	52.149			18
19	Winter	21,000	therms	¢/therm	n/a	20.890			19
20		Over	therms	¢/therm	n/a	14.269			20
21									21
22	Summer	1,000	therms	¢/therm	n/a	41.017			22
23		21,000	therms	¢/therm	n/a	20.285			23
24		Over	therms	¢/therm	n/a	12.219			24
25	**Average Rate for Small Core C&I**			¢/therm	37.554	36.908	(0.646)	-1.7%	25
26	**Average Rate for Large Core C&I**			¢/therm	18.935	18.026	(0.909)	-4.8%	26
27									27
28	***SDG&E Transport-Only*** *2,3/*		Schedule GTC-SD						28
29	Service Fees	1,000	therms	$/month	n/a	$5.08			29
30		21,000	therms	$/month	n/a	$10.16			30
31		Over		$/month	n/a	$101.57			31
32									32
33	Volumetric Charges	1,000	therms	¢/therm	n/a	49.794			33
34	Winter	21,000	therms	¢/therm	n/a	18.536			34
35		Over	therms	¢/therm	n/a	11.915			35
36									36
37	Summer	1,000	therms	¢/therm	n/a	38.663			37
38		21,000	therms	¢/therm	n/a	17.931			38
39		Over	therms	¢/therm	n/a	9.865			39
40	*Global Expense Rate 4/*			¢/therm	n/a	n/a			40

Notes 1/ Reflects historical annual average procurement rates. Actual tariff rates reflect monthly changing Schedule GPC prices.
2/ Both 1/1/2000 and BCAP authorized rates exclude an amount for Core Interstate Transition Cost Surcharges (CITCS).
3/ These rates reflect a volumetric removal of SCGas costs under SCG Schedule GT-SD from bundled transport-only rates.
4/ Global Expense Rate is eliminated as of the effective date of this decision.

TABLE 7
SAN DIEGO GAS & ELECTRIC
2000 Biennial Cost Allocation Proceeding

Summary of Illustrative Core Subscription Rates
Bundled Gas Service for Noncore Customers

	CUSTOMER GROUP			Units	Rates in effect 1/1/2000	BCAP Authorized Rates	Rate Change	%Change	
				A	B	C	D	E	
					1/	1/			
1	COMMERCIAL/INDUSTRIAL		*Schedule GCORE*						1
2	Volumetric	MPS	Winter	¢/therm	37.313	36.625	-0.688	-1.8%	2
3	Charges		Summer	¢/therm	34.639	34.085	-0.553	-1.6%	3
4									4
5		HPS	Winter	¢/therm	32.848	32.385	-0.463	-1.4%	5
6			Summer	¢/therm	30.847	30.485	-0.362	-1.2%	6
7									7
8		Transm	Winter	¢/therm	30.034	29.713	-0.321	-1.1%	8
9			Summer	¢/therm	28.701	28.447	-0.254	-0.9%	9
10									10
11		*Present*	*Proposed*						11
12	Customer	3,000	3,000	$/month	$16.25	$16.25	$0	0.0%	12
13	Charges	7,000	7,000	$/month	$84.31	$84.31	$0	0.0%	13
14	(therms)	23,000	$\boxed{21,000}$	$/month	$153.38	$153.38	$0	0.0%	14
15		126,000	126,000	$/month	$307.77	$307.77	$0	0.0%	15
16		1,000,000	1,000,000	$/month	$617.57	$617.57	$0	0.0%	16
17		Over	Over	$/month	$1,310.31	$1,310.31	$0	0.0%	17
18									18
19	AMR Charges	*all service levels*		$/month	$100	$125	$25	25.0%	19
20									20
21	AVERAGE TARIFF RATE			¢/therm	9.900	9.421	-0.479	-4.8%	21
22									22
23	ELECTRIC GENERATION		*Schedule GCORE*						23
24	Part A	*annual usage 0 - 3 million therms*							24
25	Customer Charge, per meter			$/month	n/a	**$50**			25
26	Single Volumetric Rate, all volumes			¢/therm	n/a	**30.194**			26
27									27
28	Part B	*annual usage over 3 million therms*							28
29	Single Volumetric Rate, all volumes			¢/therm	n/a	**26.994**			29
30									30
31	AVERAGE TARIFF RATE			¢/therm	29.424	27.107	-2.316	-7.9%	31

Notes 1/ Both 1/1/2000 and BCAP authorized rates reflect average annual commodity prices (Schedule GPNC) for the past year. Actual posted GCORE rates will reflect the current month GPNC price.

TABLE 8
SAN DIEGO GAS & ELECTRIC
2000 Biennial Cost Allocation Proceeding

Summary of Noncore Transport-Only Rates
Transport Service through the SDG&E & SoCalGas Systems

	CUSTOMER GROUP			Units	Rates in effect 1/1/2000	BCAP Authorized Rates	Rate Change	%Change	
				A	B	C	D	E	
1	COMMERCIAL/INDUSTRIAL:		*Schedule GTNC*						1
2	Volumetric	MPS	Winter	¢/therm	13.652	**12.964**	-0.688	-5.0%	2
3	Charges		Summer	¢/therm	10.978	**10.425**	-0.553	-5.0%	3
4									4
5		HPS	Winter	¢/therm	9.187	**8.724**	-0.463	-5.0%	5
6			Summer	¢/therm	7.186	**6.824**	-0.362	-5.0%	6
7									7
8		Transm	Winter	¢/therm	6.373	**6.052**	-0.321	-5.0%	8
9			Summer	¢/therm	5.040	**4.786**	-0.254	-5.0%	9
10									10
11	Customer	*Present*	*Proposed*						11
12	Charges	3,000	3,000	$/month	$16.25	**$16.25**	$0	0.0%	12
13	(therms)	7,000	7,000	$/month	$84.31	**$84.31**	$0	0.0%	13
14		23,000	*21,000*	$/month	$153.38	**$153.38**	$0	0.0%	14
15		126,000	126,000	$/month	$307.77	**$307.77**	$0	0.0%	15
16		1,000,000	1,000,000	$/month	$617.57	**$617.57**	$0	0.0%	16
17		Over	Over	$/month	$1,310.31	**$1,310.31**	$0	0.0%	17
18	AMR Charges			$/month	*$100*	***$125***	*$25*	*25.0%*	18
19									19
20	AVERAGE TARIFF RATE			¢/therm	9.900	**9.421**	-0.479	-4.8%	20
21									21
22	ELECTRIC GENERATORS		*Schedule EG*						22
23	Part A	*annual usage 0 - 3 million therms*							23
24	Customer Charge, per meter			$/month	n/a	**$50**			24
25	Single Volumetric Rate, all volumes			¢/therm	n/a	**6.533**			25
26									26
27	Part B	*annual usage over 3 million therms*							27
28	Single Volumetric Rate, all volumes			¢/therm	n/a	**3.333**			28
29									29
30	AVERAGE TARIFF RATE			¢/therm	5.763	**3.447**	-2.316	-40.2%	30
31									31
32	OTHER RATES:								32
33	ITCS Rate	(embedded in rates)		¢/therm	1.473	**0.790**	-0.683	-46.4%	33
34	Wheeler Ridge Acce	(in addition to rates)		¢/therm	*Based on SoCalGas Schedule G-ITC*				34

TABLE 9
SAN DIEGO GAS & ELECTRIC
2000 Biennial Cost Allocation Proceeding

Summary of Noncore SDG&E Transport-Only Rates
Transport Service through SDG&E Service Territory Only

	CUSTOMER GROUP			Units	Rates in effect 1/1/2000	BCAP Authorized Rates	Rate Change	%Change	
				A	B	C	D	E	
1	COMMERCIAL/INDUSTRIAL		*Schedule GTNC-SD*						1
2	Volumetric	**MPS**	Winter	¢/therm	10.881	**10.539**	-0.342	-3.1%	2
3	Charges		Summer	¢/therm	8.207	**8.000**	-0.207	-2.5%	3
4									4
5		**HPS**	Winter	¢/therm	6.416	**6.299**	-0.117	-1.8%	5
6			Summer	¢/therm	4.415	**4.399**	-0.016	-0.4%	6
7									7
8		**Trans**	Winter	¢/therm	3.602	**3.627**	0.025	0.7%	8
9			Summer	¢/therm	2.269	**2.361**	0.092	4.1%	9
10	**Global Expense Rate**		*1/*	¢/therm	n/a	**n/a**			10
11									11
12	Customer Charges:								12
13	0 to	3,000	therms	$/month	$16.25	**$16.25**	$0	0.0%	13
14	3,001 to	7,000	therms	$/month	$84.31	**$84.31**	$0	0.0%	14
15	7,001 to	***21,000***	therms	$/month	$153.38	**$153.38**	$0	0.0%	15
16	***21,001 to***	126,000	therms	$/month	$307.77	**$307.77**	$0	0.0%	16
17	126,001 to	1,000,000	therms	$/month	$617.57	**$617.57**	$0	0.0%	17
18	Over	1,000,000	therms	$/month	$1,310.31	**$1,310.31**	$0	0.0%	18
19	*AMR Charges*			*$/month*	*$100*	***$125***	*$25*	*25.0%*	19
20									20
21									21
22	ELECTRIC GENERATORS		*Schedule EG-SD*						22
23	Part A	***annual usage 0 - 3 million therms***							23
24	Customer Charge, per meter			$/month	n/a	**$50**			24
25	Single Volumetric Rate, all volumes			¢/therm	n/a	**4.284**			25
26									26
27	Part B	***annual usage over 3 million therms***							27
28	Single Volumetric Rate, all volumes			¢/therm	n/a	**1.084**			28
29									29

Notes 1/ The Global Expense Rate will be eliminated upon implementation of this decision.

TABLE 10

SAN DIEGO GAS & ELECTRIC

2000 Biennial Cost Allocation Proceeding

Residential Monthly Bills
(fully bundled rates)

	Monthly Energy Usage	At 1/1/2000 Rates	At Adopted Rates	Change	%Change	No. of Customers	%	Summary of Changes	
	A	B	C	D	E	F	G	H	
	therms	$1	$1	$1		584,295			
1	0	$0.00	$0.00	$0.00	0.0%	9,256	1.6%	***Increases***	1
2	5	$3.38	$3.27	($0.11)	-3.3%	18,613	3.2%	*>100%*	2
3	10	$6.75	$6.54	($0.22)	-3.3%	28,231	4.8%	*30-100%*	3
4	15	$10.13	$9.80	($0.32)	-3.2%	35,902	6.1%	*10-30%*	4
5	20	$13.50	$13.07	($0.43)	-3.2%	40,926	7.0%	*0-10%*	5
6	25	$16.88	$16.34	($0.54)	-3.2%	45,170	7.7%		6
7	30	$20.25	$19.61	($0.65)	-3.2%	47,827	8.2%	*1.6% No changes*	7
8	35	$23.63	$22.88	($0.75)	-3.2%	49,742	8.5%		8
9									9
10	***40***	***$27.44***	***$26.46***	***($0.98)***	***-3.6%***	***48,606***	***8.3%***	**Typical Bill**	10
11									11
12	45	$31.89	$30.52	($1.37)	-4.3%	44,895	7.7%	***Decreases***	12
13	50	$36.34	$34.58	($1.77)	-4.9%	40,366	6.9%	*98.4% 0-10%*	13
14	55	$40.80	$38.63	($2.16)	-5.3%	35,195	6.0%	*10-30%*	14
15	60	$45.25	$42.69	($2.56)	-5.7%	29,096	5.0%	*30-100%*	15
16	65	$49.70	$46.75	($2.95)	-5.9%	23,686	4.1%	*>100%*	16
17	70	$54.16	$50.81	($3.35)	-6.2%	18,863	3.2%		17
18	75	$58.61	$54.87	($3.74)	-6.4%	15,121	2.6%		18
19	80	$63.06	$58.92	($4.14)	-6.6%	11,418	2.0%		19
20	85	$67.52	$62.98	($4.54)	-6.7%	9,036	1.5%		20
21	90	$71.97	$67.04	($4.93)	-6.8%	6,956	1.2%		21
22	95	$76.43	$71.10	($5.33)	-7.0%	5,426	0.9%		22
23	100	$80.88	$75.16	($5.72)	-7.1%	4,220	0.7%		23
24	125	$103.15	$95.45	($7.70)	-7.5%	10,610	1.8%		24
25	150	$125.41	$115.74	($9.68)	-7.7%	3,577	0.6%		25
26	200	$169.95	$156.32	($13.63)	-8.0%	1,557	0.3%		26
27	500	$437.16	$399.81	($37.36)	-8.5%	-	0.0%		27
28	1,000	$882.52	$805.62	($76.90)	-8.7%	-	0.0%		28

Notes *All typical bills in this table include CPUC regulatory surcharges.*
1/1/2000 & adopted bill calculations reflect annualized procurement prices.
Italics & bold item reflects the overall typical bill for this customer group

TABLE 11

SAN DIEGO GAS & ELECTRIC

2000 Biennial Cost Allocation Proceeding

Small Core Commercial Monthly Bills
(fully bundled rates)

	Monthly Energy Usage	GN-1 at 1/1/2000 Rates	At Adopted Rates	Change	%Change	Customer Bills	%	Summary of Changes		
	A	B	C	D	E	F	G	H		
	therms	$1	$1	$1		310,581				
1	0	$5.08	$5.08	$0.00	0.0%	52,772	17.0%		***Increases***	1
2	10	$13.17	$12.90	($0.28)	-2.1%	57,654	18.6%		*>100%*	2
3	25	$25.31	$24.62	($0.70)	-2.7%	40,631	13.1%		*30-100%*	3
4	50	$45.55	$44.16	($1.39)	-3.1%	7,169	2.3%		*10-30%*	4
5	75	$65.78	$63.70	($2.09)	-3.2%	35,235	11.3%		*0-10%*	5
6	100	$86.02	$83.24	($2.78)	-3.2%	10,148	3.3%			6
7	200	$166.96	$161.39	($5.56)	-3.3%	24,132	7.8%	*17.0%*	*No changes*	7
8	300	$247.89	$239.55	($8.34)	-3.4%	15,018	4.8%			8
9	400	$328.83	$317.71	($11.13)	-3.4%	11,590	3.7%		***Decreases***	9
10	500	$409.77	$395.86	($13.91)	-3.4%	8,927	2.9%	*83.0%*	*0-10%*	10
11	600	$490.71	$474.02	($16.69)	-3.4%	7,008	2.3%		*10-30%*	11
12	700	$571.65	$552.18	($19.47)	-3.4%	5,588	1.8%		*30-100%*	12
13	800	$652.58	$630.33	($22.25)	-3.4%	4,432	1.4%		*>100%*	13
14	900	$733.52	$708.49	($25.03)	-3.4%	3,362	1.1%			14
15	1,000	$814.46	$786.65	($27.81)	-3.4%	2,743	0.9%			15
16	2,000	$1,294	$1,261	($34)	-2.6%	13,402	4.3%			16
17	3,000	$1,775	$1,730	($45)	-2.5%	3,960	1.3%			17
18	9,000	$4,655	$4,544	($111)	-2.4%	5,512	1.8%			18
19	21,000	$10,415	$10,171	($244)	-2.3%	1,298	0.4%			19

Notes: 1/1/2000 & BCAP authorized bill calculations reflect annualized procurement prices.

TABLE 12
SAN DIEGO GAS & ELECTRIC
2000 Biennial Cost Allocation Proceeding

Large Core Commercial Monthly Bills
(fully bundled rates)

	Monthly Energy Usage	GN-2 at 1/1/2000 Rates	At Adopted Rates	Change	%Change	Customer Bills	%	Summary of Changes		
	A	B	C	D	E	F	G	H		
	therms	$1	$1	$1		191				
1	0	$76.18	$5.08	($71)	-93.3%	0	0.0%		*Increases*	1
2	3,000	$2,172	$1,730	($442)	-20.4%	3	1.6%		*>100%*	2
3	6,000	$4,268	$3,137	($1,131)	-26.5%	2	1.0%		*30-100%*	3
4	9,000	$5,553	$4,544	($1,009)	-18.2%	2	1.0%		*10-30%*	4
5	12,000	$6,838	$5,950	($887)	-13.0%	2	1.0%		*0-10%*	5
6	15,000	$8,123	$7,357	($766)	-9.4%	5	2.6%			6
7	18,000	$9,408	$8,764	($644)	-6.8%	5	2.6%		*No changes*	7
8	21,000	$10,693	$10,171	($522)	-4.9%	8	4.2%			8
9	24,000	$11,978	$11,471	($507)	-4.2%	13	6.8%		*Decreases*	9
10	27,000	$13,263	$12,679	($584)	-4.4%	20	10.5%	*95.3%*	*0-10%*	10
11	30,000	$14,549	$13,888	($661)	-4.5%	20	10.5%	*4.7%*	*10-30%*	11
12	40,000	$18,832	$17,915	($917)	-4.9%	65	34.0%		*30-100%*	12
13	50,000	$23,116	$21,943	($1,173)	-5.1%	30	15.7%		*>100%*	13
14	60,000	$27,400	$25,971	($1,429)	-5.2%	7	3.7%			14
15	70,000	$31,683	$29,999	($1,685)	-5.3%	2	1.0%			15
16	80,000	$35,967	$34,026	($1,941)	-5.4%	2	1.0%			16
17	100,000	$44,534	$42,082	($2,453)	-5.5%	4	2.1%			17
18	125,000	$55,244	$52,151	($3,092)	-5.6%	1	0.5%			18

Notes: *1/1/2000 & BCAP authorized bill calculations reflect annualized procurement prices.*

TABLE 13
SAN DIEGO GAS & ELECTRIC
2000 Biennial Cost Allocation Proceeding

Electric Generator Monthly Bills
Transport-only rates through the SDG&E and SoCalGas systems

	Monthly Energy Usage	GTCG at 1/1/2000 Rates	At Adopted Rates	Change	%Change	Customer Bills	%	
	A	B	C	D	E	F	G	
	therms	$1	$1	$1		754		
	Part A	>> annual usage between 0 to 3 million therms <<				-		
1	0	$23	$50	$27	114.0%	54	7.2%	1
2	3,000	$236	$246	$10	4.0%	183	24.3%	2
3	6,000	$551	$442	($109)	-19.8%	60	8.0%	3
4	21,000	$1,720	$1,422	($298)	-17.3%	95	12.6%	4
5	50,000	$4,009	$3,317	($692)	-17.3%	44	5.8%	5
6	100,000	$7,560	$6,583	($977)	-12.9%	111	14.7%	6
7	126,000	$9,407	$8,282	($1,125)	-12.0%	28	3.7%	7
8	180,000	$13,700	$11,810	($1,890)	-13.8%	17	2.3%	8
9	250,000	$18,672	$16,383	($2,289)	-12.3%	52	6.9%	9
	Part B	>> annual usage over 3 million therms <<						
10	500,000	$36,429	$16,665	($19,764)	-54.3%	26	3.4%	10
11	1,500,000	$97,536	$49,995	($47,541)	-48.7%	-	0.0%	11
12	2,500,000	$161,266	$83,325	($77,941)	-48.3%	38	5.0%	12
13	10,000,000	$639,241	$333,300	($305,941)	-47.9%	22	2.9%	13
14	20,000,000	$1,276,541	$666,601	($609,940)	-47.8%	24	3.2%	14

	Adopted EG Rates		
	Part A	Part B	
Customer Charge	$50	n/a	$/meter/ month
Single Volumetric Rate	6.533	3.333	¢/month

COMPARISON RATE TABLE

SAN DIEGO GAS & ELECTRIC
2000 Biennial Cost Allocation Proceeding
Rates for Bundled Transportation through the SDG&E & SoCalGas Pipeline Systems

	CUSTOMER CLASSES		Units	Rates in Effect *Oct-98*	Rates in Effect *1/1/2000*	BCAP Authorized Rates	
			A	B	C	D	
				1/	1/	1/	
1	**Residential**						1
2	**Baseline**		¢/therm	40.374	41.429	**39.275**	2
3	**Non-Baseline**		¢/therm	61.622	62.987	**55.078**	3
4	**Class Average**		¢/therm	46.037	47.183	**42.538**	4
5							5
6	**Sm Core C&I** *(Class Average for GN-1)*		¢/therm	37.196	37.554	**36.908**	6
7	**Lrg Core C&I** *(Class Average for GN-2)*		¢/therm	18.614	18.935	**18.026**	7
8				*For comparison only*			8
9	**NGV Vehicles**	2/	¢/therm	*75.613*	*72.143*	**36.644**	9
10	**NGV Buses & fleets**	2/	¢/therm	*48.501*	*45.254*	**36.644**	10
11	**NGV Uncompressed Gas**		¢/therm	14.500	13.902	**7.516**	11
12							12
13	**Noncore Commercial & Industrial**						13
14	**Medium Pressure Service (MPS)**		¢/therm	9.889	12.237	**11.549**	14
15	**High Pressure Service (HPS)**		¢/therm	7.418	8.242	**7.786**	15
16	**Transmission (TLS)**		¢/therm	6.211	6.550	**5.206**	16
17	**Class Average**		¢/therm	8.727	9.900	**9.582**	17
18							18
19	**Electric Generation**						19
20	Cogeneration *(old rate design)*						20
21	Customer Charges		$/month	varies with usage	varies with usage	**n/a**	21
22	Transm Winter Rate		¢/therm	6.558	6.373	**n/a**	22
23	Transm Summer Rate		¢/therm	5.227	5.040	**n/a**	23
24	Other Winter Rate		¢/therm	7.288	7.103	**n/a**	24
25	Other Summer Rate		¢/therm	5.809	5.623	**n/a**	25
26	**Class Average**		¢/therm	6.192	6.003	**3.447**	26
27							27
28	Former UEG *(old rate design)*						28
29	Transmission						29
30	Demand Charges		$1000/mth	$1,365	$655	**n/a**	30
31	Igniter Fuel	3/	¢/therm	15.666	*11.006*	**n/a**	31
32	Tier1 Volumetric	3/	¢/therm	3.599	*5.078*	**n/a**	32
33	Tier2 Volumetric	3/	¢/therm	1.575	*4.083*	**n/a**	33
34							34
35	Distribution						35
36	Demand Charges		$1000/mth	$51	$25	**n/a**	36
37	Igniter Fuel	3/	¢/therm	15.666	*11.006*	**n/a**	37
38	Tier1 Volumetric	3/	¢/therm	45.633	*25.727*	**n/a**	38
39	Tier2 Volumetric	3/	¢/therm	19.945	*13.108*	**n/a**	39
40							40
41	**Class Average**		¢/therm	6.199	5.679	**3.447**	41
42							42
43	Adopted Rate Design		*Transport through the SDG&E & SoCalGas systems*				43
44	**Part A** Customer Charge		$1/month			**$50**	44
45	Volumetric Rate		¢/therm			**6.533**	45
46	**Part B** Volumetric Rate		¢/therm			**3.333**	46
47	**Class Average**		¢/therm	n/a	n/a	**3.447**	47

Notes: 1/ Class average rates are derived from SDG&E's "Summary of Cost Allocation" tables.
All other rates are derived from SDG&E's rate tables for "bundled" transportation services.
2/ Transport-only services were not available for these customers; the present rates reflect "equivalent" proxies.
3/ These rates reflect the sum of charges under SDG&E Schedule GTUEG-SD and SoCalGas Schedule GT-SD.

(END OF APPENDIX E)

APPENDIX F

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Last updated on 18-NOV-1999 by: ACB
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(END OF APPENDIX F)

Dissent of Commissioner Bilas:

I respectfully dissent from the opinion of the majority on this Biennial Cost Allocation Proceeding because I find the order to contain one serious misstep in regulatory judgment – the adoption of a "Sempra-wide" rate for gas transportation to electric generation customers.

Let me first point out that I am supportive of the bulk of the order. I do not disagree with the adoption of the parties' Joint Recommendation and I am pleased that the order incorporates an amendment I sponsored regarding the Residual Load Service (RLS) Tariff. I believe it is a prudent course of action for this Commission to require Southern California Gas Company to file an application for a peaking tariff to replace the RLS tariff. I am confident that a replacement peaking rate can be in place within a year so that the debate over the RLS tariff can forever be extinguished.

That being said, I cannot lend support for an order that so blatantly departs from economic principles of rate design by adopting a rate for electric generators that subsidizes one set of customers at the expense of another set of customers. There is no doubt that I have reviewed this issue exhaustively from all angles. I have found this to be a close call between economic principles and policy interests. On the one hand, there are compelling policy and public interest arguments to provide relief to San Diego area generators through the Sempra-wide rate. A rate that is averaged over the entire Sempra base of electric generation customers could provide an extra incentive for power plant development in the San Diego region. On the other hand, there are many sound economic arguments to allow market-based solutions to San Diego's energy needs rather than relying on Commission intervention at this point in time. Being a free market economist, I believe we must not impose regulatory solutions over market forces. Central planning such as this is antithetical to believing in competitive markets.

Given my background and experience with these issues, I net out in favor of the economic arguments against the Sempra-wide rate. While I realize there is certainly a need for new generation to come on line in the next few years to serve load growth in the San Diego area, I do not believe the record can assure us that the Sempra-wide rate will guarantee new construction, or that the lack of a region-wide rate will definitely prevent it. Indeed, the evidence in the case has shown new generation owners locating or making plans to locate in the San Diego area well aware of the current gas transportation pricing differences.

I prefer to look towards solutions that give direct market-based pricing signals to generation and transmission investment rather than a solution such as the Sempra-wide rate that indirectly tries to rectify problems in the electric market by tinkering with pricing signals in the gas market. I am cognizant of current efforts by the California ISO and stakeholders to refine the market structure in wholesale electric power markets in response to the recent FERC order on congestion management by the ISO (90 FERC para. 61,006 (2000). The congestion management reform process is fine tuning the locational pricing mechanism for wholesale electricity. When this reform process is complete, it should provide a vehicle for adequate pricing signals in the wholesale electric market. In contrast, the Sempra-wide rate is nothing more than de facto central planning because it is the Commission's attempt to site power plants through gas pricing policies where electric markets are unable to do so. I would prefer to fix the underlying electric market structure instead. Didn't this Commission learn its lesson from the ill-fated BRPU?

Therefore, I do not find the arguments in support of a Sempra-wide rate sufficient to counteract the enormous change in rate design policy this Commission is making by forcing Los Angeles area generators to subsidize San Diego generators. I am not prepared to make such a policy shift at this time to force an outcome that we cannot be assured will actually work. Those who endorse the Sempra-wide rate argue that in addition to stimulating generation in San Diego, it will lower the PX price and lower RMR contract costs. I do not find these arguments convincing since effects on the PX price are unduly speculative. Furthermore, any lowering of RMR payments to San Diego generators could arguably be counteracted by increases in RMR payments to Los Angeles area generators. Because the Sempra-wide rate could distort pricing signals in the wholesale electric market, it is not an outcome I wish to endorse.

Instead, I would prefer this Commission pursue market-based solutions to balance regional energy supply and demand. These solutions could include working with the ISO and PX to reconfigure their pricing systems as well as deployment of distributed generation technologies. I would also prefer that any special subsidies that San Diego area generators and developers require be handled through direct grants to developers. From an economist's perspective, a targeted and transparent solution is always preferable to one that incorporates hidden subsidies and pricing distortions.

/s/ Richard A. Bilas
RICHARD A. BILAS
Commissioner

San Francisco, California
April 20, 2000