PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Commission Advisory and
Compliance Division
Energy Branch

RESOLUTION G-2948
May 22, 1991

R E S O L U T I O N

RESOLUTION G-2948. Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCal), and San Diego Gas and Electric Company (SDG&E) submit proposed tariffs and rules to comply with decisions rendered under Order Instituting Rulemaking (OIR) 90-02-008 on the Commission's own motion to change the structure of gas utilities' procurement practices and to propose refinements to the regulatory framework for gas utilities.

By PG&E Advice Letters 1624-G and 1624-G-A, filed on January 10 and March 26, 1991; SoCal Advice Letter 2009, filed on January 10, 1991; and SDG&E Advice Letters 740-G AND 744-G, filed on January 10, 1991 and December 29, 1990.

SUMMARY

This Resolution conditionally approves the advice letters identified above, with modifications. It also:

Adopts the utilities' revised open seasons.

Upholds the two-year requirement for firm service commitments. The two-year commitment may be reconsidered at the time capacity brokering is implemented. We will be very sympathetic to the issues raised by our adopted two-year commitment.

Expands the full-requirements option to Service Level 3 to provide more flexibility for customers which cannot predict their gas requirements accurately due to seasonal demands.

Specifies that transportation of customer-owned, California produced gas shall not be curtailed due to deficiencies or other problems affecting the delivery of gas from the interstate pipeline system.

Modifies the curtailment rules for capacity and supply, adopting the protocol of the service levels, and drops the requirement of the utilities to define whether the curtailment is due to supply problems or capacity problems.

Modifies the SL-3 curtailment pattern to provide cogeneration parity, following the same mechanism adopted for Service Levels 4 and 5.

Adopts a program to suspend alternate fuel requirements for customers with standby facilities installed, whether currently operating or no longer operating.

Adopts a buy-up option proposed by PG&E to allow customers to use as-available capacity during the summer months temporarily under the firm, Service Level 2.

Allows a Service Level 2 customer to negotiate a demand change if its circumstances have changed dramatically.

Provisionally adopts SDG&E's single gas portfolio with three subaccounts: Core, Core Subscription, and Noncore.

Denies the utilities' noncore trigger proposals.

Orders compliance tariff filings and settles lesser issues.

Appendix A presents a glossary of terms and acronyms used throughout this resolution.

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BACKGROUND

1. On November 1, 1989 the Commission held an informational en banc hearing to evaluate its natural gas program for gas procurement and transmission services which became effective on May 1, 1988. Numerous complaints alleged excessive market power of the regulated utilities in noncore gas procurement and nomination problems for transporting natural gas.

2. On February 7, 1990 the Commission issued Rulemaking (R.) 90-02-008 to change the structure of gas utilities' procurement practices for noncore market and obtain proposals for efficient procurement and transportation of natural gas for all customers.

3. Written comments in R.90-02-008 were filed by a number of parties and a Settlement and Agreement (Settlement) was filed by the Settlement Parties on August 15, 1990. The Settlement Parties were:

Mock Resources, Inc.
Pacific Gas and Electric Company (PG&E)
Southern California Gas Company (SoCal)
San Diego Gas and Electric Company (SDG&E)
Toward Utility Rate Normalization (TURN)
California Industrial Group (CIG)
California League of Food Processors
California Manufacturers Association
GasMark, Inc.
Enron Gas Marketing, Inc.

4. D.90-09-089 dated September 25, 1990 under R.90-02-008, adopted new rules for gas procurement and transportation services for utility noncore customers. This decision adopted only elements of the Settlement. (See Appendix A for a Glossary of Terms.)

5. In Decision 90-09-089, the Commission approved a proposal contained in the Settlement to permit the utilities to use their firm interstate transportation capacity rights to effect buy/sell arrangements with their customers. The utilities would purchase gas supplies identified by their customers in the various producing basins and would resell the identified gas supplies to the customer in California at the same purchase price plus the cost of interstate and intrastate transportation. The arrangement was a method of providing customers with access to the utilities' firm interstate transportation capacity rights in advance of an approved capacity brokering program.

6. Noncore customers may choose to purchase gas and transportation services (as core-subscription) from the utility or may opt to transport their own gas. Noncore customers may also split their loads, to receive some utility-procured gas and gas from another source. In order to achieve transportation of self-purchased gas, customers must select from four Service Levels of reliability:

Service Level 2: Two-Year Commitment, Firm Service
Service Level 3: Annual Commitment, Interruptible
Service Level 4: Monthly Commitment, Interruptible
Service Level 5: Daily Commitments, Interruptible

Service Level 2 currently contains a two-year commitment by the customer. This Resolution does not modify that requirement. Upon implementation of a full capacity brokering program, we will be very cognizant of the need to provide an orderly transition. We recognize that a two-year commitment for Service Level 2 customers could cause substantial harm to our capacity brokering program. We therefore will be very sympathetic to the issues raised by our adopted two-year commitment.

7. This program goes into effect August 1, 1991. Customers have been participating in open seasons to select their Service Level options and arranging gas purchases.

8. D.90-09-089 set the following schedule for Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCal), and San Diego Gas and Electric Company (SDG&E) for implementing the new gas procurement rules:

By November 10, 1990	Utilities's proposed tariffs to all parties.
*November - December	Workshops to address proposed tariffs and other implementation issues.
By January 10, 1991	Advice Letter Filings
August 1, 1991	Full Implementation

*Workshops were held in December, 1990.

9. The Commission issued D.90-12-100 in mid-December to address various petitions to modify D.90-09-089.

10. Utility advice letters (A.L.) were filed on January 10, 1991 to comply with D.90-09-089 and D.90-12-100.

A.L. 1624-G	PG&E
A.L. 2009	SoCal
A.L. 740-G	SDG&E

11. In February, the Commission issued D.91-02-022 and D.91-02-046 responding to more petitions to modify and applications for rehearing of D.90-89-089. The advice letter filings received on January 10, 1991 did not contain the changes or modifications required by these later decisions.

12. A Prehearing Conference in R.90-02-008 was held during the last week of April to address perceived implementation problems. A workshop was held on May 9 to provide more discussion of the elements of the program.

NOTICE

1. Public notice of the above mentioned advice letters was made by publication in the Commission calendar and by each respective utility's mailing copies to other utilities, governmental agencies, to the service list of OIR 90-02-008, and to all interested parties who requested notification.

PROTESTS

1. Protests were received from

Alberta Petroleum Marketing Commission (APMC),
Indicated Producers (IP)
Southwest Gas Corporation (Southwest)
Toward Utility Rate Normalization (TURN)
California Industrial Group (CIG, which includes California Manufacturers Association and California League of Food Processors)
California Cogeneration Council (CCC)
Division of Ratepayer Advocates (DRA)
Cogenerators of Southern California (CSC)
State of California, Department of General Services (DGS)
Southern California Edison Company (SCE)
San Diego Gas and Electric Company (SDG&E), and
The City of Long Beach (Long Beach).

See Appendix B for the list of protests to PG&E, SoCal, and SDG&E's advice letter filings.

TRANSPORTATION

Buy/Sell Arrangements
IP protests the utilities' buy/sell arrangements as a violation of Federal Energy Regulatory Commission (FERC) rules requiring the issuance of brokering certificates by that agency before such rights are given to third parties. IP filed a petition for rehearing which was addressed by D.91-02-022.

IP and SCE protest the lack of any provision in the SoCal tariffs for buy/sell arrangements or their operation. IP argues that without a proposed tariff there is no way for end-users or producers to know how SoCal intends to conduct such arrangements. IP also expresses concern that PG&E's arrangement (Schedule G-CIG) does not protect customers' rights to price confidentiality. IP is concerned that the price negotiated between the customer and the producer will not remain confidential from PG&E's gas purchasing department and therefore the customer will be disadvantaged. IP proposes that PG&E offer to purchase the identified gas from the end-user at the system WACOG (weighted average cost of gas) and to resell it at the same price, as is proposed by SoCal. This will eliminate the need for PG&E to know sensitive purchase price information.

CIG also objects to the PG&E provision which requires a customer to waive all confidentiality rights as to the commodity purchase price if it should fail to pay its utility bill. CIG believes that the confidentiality of the commodity purchase price should only be waived to the extent that PG&E commences an action to recover unpaid bills.

SoCal agrees that there is insufficient detail provided in its advice letter filing outlining its targeted sales program. SoCal comments that it is still preparing a more detailed statement of the terms and conditions of the program. SoCal states that part of the delay is due to the pending FERC decision to be issued concerning a capacity brokering program for the El Paso Natural Pipeline Company (El Paso) and the Transwestern Pipeline Company (Transwestern). If the FERC has not acted, removing the need for a "targeted sales program," SoCal will submit tariffs providing the necessary details.

PG&E responds that it is aware of the need to keep the gas price negotiated between the customer and the producer confidential and has hired an outside accounting firm to determine the specific measures it will take to keep price information confidential.

Discussion
In Decision 90-09-089, the Commission approved a proposal contained in the Settlement to permit the utilities to use their firm interstate transportation capacity rights to effect buy/sell arrangements with their customers. The utilities would purchase gas supplies identified by their customers in the various producing basins and would resell the identified gas supplies to the customer in California at the same purchase price plus the

cost of interstate and intrastate transportation. The arrangement was a method of providing customers with access to the utilities' firm interstate transportation capacity rights in advance of an approved capacity brokering program.

PG&E would implement these buy/sell arrangements under its proposed Customer Identified Gas Program, Schedule G-CIG. SoCal describes its buy/sell arrangements under a Targeted Sales Program. SoCal filed this program under a separate advice letter.

SoCal filed Advice Letter 2028 on April 19, 1991 outlining its Targeted Sales Program under a new schedule. Advice Letter 2009 contains a placeholder in a number of its tariff schedules:

> "Customers may enter into a special agreement with Utility for firm capacity rights on the interstate pipeline system."

This "placeholder" should be deleted from Advice Letter 2009 and should be replaced with appropriate language, omitting the statement that the customer may enter into a special agreement with the Utility for firm capacity rights on the interstate pipeline system. Utility customers are not authorized to hold firm capacity rights on the interstate pipeline system at this time, nor is SoCal allowed to write contracts to provide this right to its customers. CACD recommends that SoCal's language incorporate that the customer may make a special agreement with the Utility to transport on a best efforts basis the customer arranged gas and to sell the gas to the customer.

PG&E's program does raise issues of price confidentiality. However, PG&E has taken precautions to maintain price confidentiality by using an outside accounting firm to handle the transactions. This should assuage the fears of IP and CIG. CACD believes that PG&E's mechanism achieves the desired result.

CIG also objected to PG&E's requirement that a customer waive its commodity purchase price confidentiality rights should it fail to pay its bill. CIG would allow this requirement only under the circumstance that PG&E commences an action to recover unpaid bills. CACD disagrees with CIG's recommendation and suggests that PG&E not modify its tariffs.

<u>Open Seasons</u>

Decision 90-09-089 prescribed a 120-day time period from the date of the utility's notice of the tariff procurement changes for customers to choose Service Level options. This time period is called an open season.

SoCal has announced that its open season for service level elections begins January 15 and ends May 15. TURN, CIG and IP protest the May 15 closing date of SoCal's open season as too early. TURN suggests starting March 15 and ending July 15, parallel to PG&E's dates. TURN adds that if PG&E can accomplish the changes by the later closing date, then SoCal can as well. IP would have the open season end between July 20-25.

CIG wants the open season dates as uniform as possible for each utility and does not want to have the open season close before the utilities have Commission approved tariffs. CIG requests sufficient time for customers to familiarize themselves with the final details of the tariffs and to make the necessary service arrangements. TURN believes that it is unrealistic to hold separate open seasons for transportation and supply, and argues that customers would want to arrange both service elements at the same time. DGS objects to PG&E's April 15 deadline in Schedule G-CIG. DGS argues that customers who do not make procurement arrangements by that date risk losing rights under PG&E's tariff since capacity will have been awarded. CIG argues that SDG&E does not disclose details regarding its open season process. CIG urges that the Commission keep a uniform open season for the three utilities.

The APMC and the Canadian Producer Group (CPG) believe that PG&E's new open season, which began on April 1, 1991, has created uncertainty. DGS objects to PG&E's April 15 deadline in its Customer-Identified Gas Program, Schedule G-CIG. DGS argues that customers who do not make procurement arrangements by that date risk losing rights under PG&E's tariff since capacity is awarded at the various points on a first come first served basis. DGS states that the tariffs are not approved yet and it is inappropriate for PG&E to use unapproved tariffs that may lead to loss of a customer's right to pipeline capacity. DGS requests that enough time be allowed for the customers to review the tariffs after they have been approved by the Commission. DGS requests that May 15, 1991, or at least 14 days after the distribution of the approved tariffs be the effective date of such tariffs.

SDG&E responds that it believes that its open season is timed appropriately. SoCal responds that it requires sufficient lead time between May 15 and August 1 to modify its accounting and billing systems and to accommodate the iterative process of capacity allocation across pipelines and at constraint points. SoCal argues that this process cannot be started until after service levels are awarded, and it envisions that a month is required to complete the iteration if a particular pipeline or constraint point is oversubscribed.

SoCal argues that the chosen date was intended to allow noncore customers to contract for firm transportation supplies on a longer-term basis, and that it is not reasonable to expect customers to contract for supplies as late as July 20 or 25th, as is suggested by IP, only to learn that a particular supply path was unavailable.

SoCal adds that it encountered significant accounting and billing problems accommodating the required changes of the May, 1988 restructuring and that it wants to avoid a similar occurrence this time. SoCal states that should the Commission order it to extend the close of the open season, it requires an equal time extension for the commencement of service.

PG&E responds that any service agreement received by PG&E before, on, or after April 15, 1991 will be considered on a first-come first-served basis on or after April 15, 1991 for allocation of natural gas. PG&E further states that this only affects deliveries via Topock. PG&E therefore, objects to changing the G-CIG service Agreement date to May 15, as requested by DGS.

PG&E also responds that it has acted in good faith to follow the guidelines set out by the CPUC and has kept parties informed of its efforts to implement its program in accordance with the OIR.

Discussion
The Commission held a prehearing conference on April 26, to discuss a number of major issues having an impact on the implementation of the procurement decisions. In response to this prehearing conference, SoCal informed CACD that it would extend its open season closing date from May 15 to approximately June 10. SDG&E informed CACD that it was extending the closing date of its open season from May 31 to June 21. PG&E has maintained its dates, which began April 15 for sign-ups for deliveries at Topok until SL-2 capacity is met, and from April 15 to May 15 for the first round of SL-2 capacity on PGT. The second allocation of PGT capacity will be made by June 3. CACD believes these changes will provide sufficient time for customers to make their service elections.

Capacity Designation
CIG objects to the supply basin designation in PG&E's Customer Identified Gas (G-CIG) tariff. CIG states that customers should not have to specify to PG&E, on an annual basis, a particular supply basin. CIG argues that PG&E itself does not have fixed capacity rights to each supply basin accessed by El Paso's system. CIG believes that this provision will create major problems for the marketers and customers.

PG&E responds that it requires this information in order to:

1) contract with the supplier identified by the customer, and

2) provide greater assurance that supplies requested can be delivered, consistent with facilitating firmer service to noncore customers.

PG&E adds that it will determine the specific El Paso allocations based on its historical supply basin receipt and will inform customers during the open season whether G-CIG service is available from the requested basin. PG&E believes that this will provide the customers with better service and greater certainty of receipt of their gas supplies.

Discussion
CACD recommends that PG&E be allowed to require supply basin specification from its noncore customers on an annual basis in order to assure reliable delivery of supplies and to provide information to other noncore customers about supply basin availability for as-available demands.

Capacity Limitation
APMC states that PG&E intends to cap the amount of available capacity for noncore customers to 250 MMcf/d (thousands of cubic feet per day) at the Malin receipt point and 200 MMcf/d at the Topock receipt point on a monthly basis. This limitation is applied by requesting the customers to specify their monthly requirements based on their historical load profile or a constant baseload quantity. PG&E will then cut off the availability of the service in any month when the amount of contracted service reaches 250 MMcf on its northern system and 200 MMcf on its southern system.

APMC believes the monthly limitation will restrict some noncore customers' ability to contract for sufficient volumes because their gas requirements may exceed the monthly limitation. APMC also fears that this procedure will result in an annual under-utilization of the capacity. To remedy this situation, APMC submits three proposals:

1) In any month, the amount of contracted service can be restricted to within plus or minus ten percent of the available daily capacity. The availability of service would end when the annual average of contracted volumes during the open season reaches 250 MMcf/d (or 91.25 Bcf) of total annual volumes on the northern system.

2) The monthly limitations could be varied above or below 250 MMcf/d in proportion to the recent historical monthly profile of the noncore, non-UEG market. Under this, if during any month the historical noncore, non-UEG load has averaged 5 percent above the annual average, the limit on the northern system for that month would be 262.5 MMcf/d.

3) The CPUC could relax the restriction that customers take service for either a baseload amount or for a profile which follows their historical monthly usage in those months when the service is fully subscribed. This would permit suppliers to fill in undersubscribed months with customers who would use the service under Service Level 2 for only part of the year.

AMPC states that the annual average would never exceed the prescribed capacity limits under any one of these options.

PG&E claims that the Settlement intended to recognize the 200 MMcf and 250 MMcf per day volumetric restrictions on a daily basis and not monthly or annually. PG&E also argues that allowing the service to exceed these limits places core customers at a disadvantage, forcing them to purchase gas from more expensive southwest sources rather than the less expensive Canadian gas.

PG&E opposes adoption of APMC's proposed Options 1 and 2, but is willing to accept Option 3, with some modifications. After the open season, PG&E states that it is willing to modify its interruptible transportation service (Schedule G-IT) to allow conversion from Service Level 3 (SL-3) to Service Level 2 (SL-2), providing customers a "buy-up" option in months when the capacity is not fully contracted. Under the "buy-up" option, customers may elect, prior to the beginning of the month, to pay the firm Service Level 2 transport rates (Schedule G-FT) to receive access to customer identified gas supplies within the designated allocation. This option will be available only after the open season closes and thereafter, only during the summer months (April through October).

<u>Discussion</u>
PG&E's capacity limitations on its northern and southern systems coupled with customer requirements to specify their monthly demands or a constant baseload quantity may result in capacity underutilization and may restrict some customers' ability to meet their needs. PG&E is willing to adopt APMC's third proposal to achieve a more optimal result. PG&E offers to allow customers a "buy-up" option from Service Level 3 to Service Level 2, when capacity is available, limited to the months of April through October. CACD recommends that the Commission approve this buy-up option for all utilities. This will serve to optimize capacity use and will allow customers the flexibility to gain additional supplies during times when capacity is available.

<u>Contract Quantities</u>
CIG objects to PG&E's contract quantity requirements which require the customer to specify an annual (ACQ) and monthly contract quantity (MCQ) for each supply basin. CIG also objects that there is no provision for adjustment of monthly quantities.

PG&E responds that the monthly quantities are required in order to determine when the G-CIG service is fully committed. PG&E argues that a customer's maximum daily quantity (MDQ) may only occur on a few days during the year, and if PG&E were to only consider the MDQ, then some customers may be denied service even though service is actually available. PG&E adds that the monthly quantity is also needed to prevent Schedule G-CIG from being over-committed in certain months due to customer seasonal patterns, thereby disadvantaging PG&E's core and Core Subscription customers.

Discussion

PG&E needs to manage a number of customers' needs year-round. Without a specific set of supply path designations for annual and monthly use, PG&E will not be able to assist some customers to match available supplies and locations, nor will it be able to achieve capacity optimization. CACD believes that it is reasonable for PG&E to require an ACQ and an MCQ by supply basin. In conjunction with the discussion above, CACD believes that somo of CIG's concerns for its seasonal clients will be met with the availability of a "buy-up" option during the summer months of April through October.

Capacity Use by Noncore Customers

CIG objects that PG&E's Schedule G-CIG for Customer-Identified Gas is only available to Service Level 2 customers. CIG states that SL-3 through SL-5 noncore customers must have a reasonably reliable transportation service available to them since utility-procured gas will only be available under core-subscription.

PG&E responds that service under PG&E's Customer-Identified Gas Program will be available to customers under Service Levels 3 through 5 on a non-discriminatory, as-available basis.

Discussion

Firm transportation service is available to all noncore customers at Service Level 2. This service level should provide reliable transportation of customer-owned gas. As-available service for interruptible transportation of customer-owned gas (Service Levels 3 through 5) is provided under PG&E's customer identified gas program, Schedule G-CIG. This service should also prove to be reliable, because PG&E has experienced few curtailments over the past years. CACD recommends approval of PG&E's Customer-Identified Gas Program.

Capacity Reservations - PG&E's Seasonal Restrictions

CIG objects to PG&E's customer requirement to provide monthly contract quantity nominations under Core Subscription (Schedule G-CS) and Firm Transportation (Schedule G-FT) service. CIG believes that this restriction imposes a "seasonal" use-or-pay system that was not part of D.90-09-089 or the Settlement. CIG adds that this limitation will severely hamper noncore customers trying to deal with short-term fluctuations. CIG requests that PG&E eliminate the seasonal requirement. Instead, CIG recommends that customers be allowed to adjust their monthly quantities within a given season so that the total monthly quantities for that season do not exceed the monthly quantities originally estimated for the season by more than 20 percent.

CIG also objects to the provision of PG&E's interruptible transportation service (Schedule G-IT) which prevents Service Level 3 (SL-3) customers from adjusting their monthly quantities in excess of a pre-established seasonal quantity. CIG believes that such a provision denies reasonable flexibility to the customer and effectively imposes a seasonal use-or-pay requirement.

In response, PG&E refers to page 28 of the Settlement and page 26 of D.90-09-089, which state that annual volumes may be adjusted seasonally in accordance with historic usage patterns, as provided in D.88-03-085. PG&E then cites the provision in D.88-03-085, which states that the utilities shall impose reasonable restrictions on the monthly contract quantities of partial requirement, core-elect customers in order to discourage "winter-only" core-election. PG&E believes that allowing any greater flexibility can lead to abuse of the service level concept during periods of high demand. PG&E adds that the 20% tolerance proposed by CIG would cause similar problems.

Discussion

CIG is concerned that the restrictions imposed by PG&E's ACQ and MCQ quantity specifications will promote a system of rigid constraints on customers with varying monthly demands during processing or harvesting seasons and that, in effect, PG&E's rules impose a "seasonal" use-or-pay arrangement. CIG proposes a 20% tolerance band instead of the adopted 10% value to allow for errors in specifying the exact quantities needed in specific months.

PG&E argues that widening the tolerance band to 20% will achieve greater capacity restrictions during months when demand is constrained. With the adoption of the proposed "buy-up" option, customers should be able to meet their variable requirements with greater flexibility. CACD believes that the annual and monthly quantity specifications required by PG&E are reasonable to ensure effective use of the capacity for all customers.

PG&E's Firm Service MDQs

CIG points out that PG&E's tariff service for firm transportation (Schedule G-FT, SL-2) is inconsistent with the service provided to those firm service customers which opt for utility procurement. CIG argues that customers who elect service under schedule G-FT must specify an annual contract quantity (ACQ) and a maximum daily contract quantity (MDQ). CIG adds that if a firm service customer also elects utility procurement service under the customer identified gas service, (G-CIG), a monthly contract quantity (MCQ) specification is required. However, the monthly requirement does not apply to those firm service customers who do not purchase utility gas. As a consequence, these customers will be allowed to adjust their monthly requirements. CIG is concerned that the tariffs do not treat all G-FT customers equally.

CIG is also concerned that core subscription customers are allowed flexibility in their monthly requirements that the firm transportation customer who chooses utility procurement does not have. CIG believes that customers' obligations under the G-CIG schedule should be kept separate from their obligations under firm service, and in addition, all G-FT customers should have the same obligations. CIG recommends that G-FT customers provide a preliminary estimate of their monthly requirements which they should be permitted to modify up to four business days prior to the beginning of each month.

Discussion
PG&E agrees that the 450 MMcf per day limitation of the total capacity available for firm transportation customers imposes stricter monthly nomination requirements than service to those firm transportation customers electing to procure utility supplies. PG&E proposes to modify its tariff to allow the equal flexibility, provided the capacity is available within the 450 MMcf/d allocation. CACD agrees and recommends that PG&E change the inconsistencies between its Schedules G-FT and G-CIG.

SoCal's MDQ Program Details
CIG states that there should be greater detail in SoCal's tariffs covering maximum daily contract quantities and loads split between service levels.

SoCal believes that the current tariff filing provides as much detail about the establishment of maximum daily contract quantities and allocation of consumption between multiple service levels for the same customer as is possible to state on a basis of general application. CIG has made no proposals on these points.

Discussion
SoCal includes a full description of annual and seasonal contract quantities in its service operations manual, but does not reference MDQs, MCQs, or ACQs in the body of the tariffs. The most that is stated is that "the customer must nominate a stated annual volume which may include seasonal variations in accordance with the customer's historic usage patterns." CACD suggests that it is reasonable for SoCal to include a definition of Maximum Daily Quantities, Monthly Contract Quantities, and Annual Contract Quantities in the tariffs and, at least in Rule 1, to provide clearer, general understanding of the terminology and the requirements.

SDG&E's MDQ Program
DRA believes that the Maximum Daily Quantity (MDQ) for core subscription service should be allowed to deviate from the 110% standard, if the customer provides evidence justifying such a change. DRA notes that the Commission's intent was to establish an MDQ based on negotiations between Service Level 2 and 3 customers and the utility (D.90-12-100, page 6, Appendix).

SDG&E believes that its provision for 110% of peak-day demand is more lenient than the proposals of other utilities. However, SDG&E agrees that there may be situations when a customer should be allowed to deviate from the 110% standard, and if this were to occur, negotiations would be required. SDG&E will file revised tariffs reflecting negotiated MDQ's for SL-2 and SL-3 customers in circumstances justifying a change from the 110% standard. It will also include language on the establishment of a new MDQ in the current month, as was proposed during the workshops.

<u>Discussion</u>
Decision 91-02-022 (page 6, Appendix) states that the customer's Maximum Daily Quantity for SL-4 (monthly service) will be equal to a customer's contract quantity for the month expressed in MDth (thousands of decatherms) per day. For SL-2 and SL-3 (annual contracts), the utility shall negotiate an MDQ that is consistent with the expected monthly demand profile of the customer. Also, the decision provides that the customer's average MDQ over the year will have to exceed the annual contract quantity in order to account for daily and monthly gas usage changes.

SDG&E's core subscription service meets the requirements defined by the Commission for MDQs. To allow such customers to deviate from the 10% tolerance level can disrupt transportation for lower service levels. However, CACD believes that it is reasonable to allow a renegotiation of an MDQ if the customer's position has changed significantly. SDG&E, SoCal and PG&E should be allowed to add this provision to their tariffs.

CURTAILMENTS

<u>Supply/Capacity Curtailments</u>
DRA, SCE and CIG protest that SoCal has not detailed the implementation of curtailments within a given service level sufficiently, that it fails to distinguish between supply and capacity curtailments, and fails to indicate that customer-owned gas will not be curtailed in the event of a shortage of utility gas supplies. DRA recommends the following curtailment order for supply shortages (curtailed first to last):

SL-2, UTILITY PURCHASES BY END-USE PRIORITY
SL-5, CUSTOMER PURCHASES BY TRANSPORT PRICE *
SL-4, CUSTOMER PURCHASES BY TRANSPORT PRICE *
SL-3, CUSTOMER PURCHASES BY END-USE PRIORITY *
SL-2, CUSTOMER PURCHASES BY END-USE PRIORITY *

* Customer purchases would only be curtailed to prevent the curtailment of CORE loads (SL-1).

SoCal replies that neither it nor PG&E made a distinction between supply and capacity curtailments in their advice letter filings. SoCal submits that under the new services providing access to inter- and intrastate capacity effective August 1, 1991,

> "it will be impossible as a matter of practical operation to distinguish between a "supply" shortage and a "capacity" shortage. On cold days when deliveries from interstate pipelines fall below levels nominated by SoCalGas and its

customers collectively, there is insufficient information available immediately from the interstate pipelines as to which customer' gas was delivered and which customers' gas was not delivered. It is impossible to make distinctions as to which SoCalGas customers should be curtailed in such an emergency when the necessary information is just not available on a timely basis."

CIG states that PG&E's changes to its Curtailment Rule 14 are unclear and requests further clarification regarding a localized curtailment. CIG believes that shortages on the interstate system should not affect the delivery of localized supplies. CIG recommends the rule be modified to provide that if curtailment at the customer's delivery point will provide no system benefit or benefit to any other customer with a higher service level, then PG&E will not curtail that customer. CIG adds that PG&E's Rule 14, Section C should state that curtailment of customer-owned gas (absent emergency circumstances) will occur at the point of delivery only if there is a capacity problem on PG&E's system.

PG&E responds that the Commission has ordered a uniform service level and priority system without regard to supply source or cause of service. PG&E also states that its 48-hour notice before curtailing addresses any concerns for confiscation of customer-owned gas by allowing the customers to change nominations. PG&E believes that this notice allows time for the customer to seek another market, such as a customer with a higher service level in need of supplies.

<u>Discussion</u>

Prior to the gas restructuring of May 1, 1988, the rules for supply and capacity curtailments were equal. Either curtailment was administered by the end-use priority protocol. After May 1, 1988 the rules for supply curtailments changed, while those for a capacity curtailment were maintained. If a supply curtailment occurred, the utility first would curtail gas destined to its noncore portfolio customers by end-use priority and then next to core-elect portfolio customers by end-use priority 5 (P-5) through priority P-2B, before it could divert customer-owned supplies to protect the core. The unmodified, adopted rules for a supply curtailment from D.86-12-010 (p.122) state:

> "Utility gas service will be curtailed whenever demand for utility procurement exceeds utility supplies. Customers purchasing gas from the noncore market portfolio will always be curtailed before those taking gas from the core market portfolio. Curtailment within a given portfolio will be based on current end-use priorities. Utilities may direct customer-owned gas from transmission-only customers to serve P-1 and P-2A customers receiving gas from the core portfolio only after all other curtailment steps have been taken and the Commission declares a supply emergency."

These protocols were adopted to foster transportation of customer-owned supplies and to levelize the playing field for transporters with the utilities.

CACD asked SoCal to respond further to the supply side of this issue. In its reply, SoCal states that "if supply failures occur, the interconnecting pipeline will make a "best efforts" attempt to reduce confirmed nominations to the level of flowing gas. Unless other information is available, reductions will be made on a pro rata basis."

What this means is that the interconnecting pipeline will adjust the individual volume number amounts in its accounting transactions, if it has the real-time knowledge that the gas is not flowing. But the likelihood of this immediate knowledge is small, and so a pro rata adjustment to the level of the gas that is flowing is made. A final accounting adjustment is made much later, when the actuals are accumulated.

In its letter, SoCal argues that under the new procurement rules, customers are encouraged to transport their own supplies and that SoCal expects that the result of this will produce fewer noncore customers purchasing Utility gas. SoCal asserts that those purchasing gas from the utility will be smaller, less sophisticated users who would bear the brunt of a supply curtailment, should one occur.

None of the decisions under R.90-02-008 specified any change to the outstanding rules for a supply curtailment as outlined under OIR 86-06-006 and adopted by D.86-12-010, apart from the removal of the noncore portfolios for PG&E and SoCal.

CACD has had additional conversations with the utilities on the topic of supply curtailments. Representatives from both PG&E and SoCal have discussed this issue before interested gas parties in the prehearing conference and the workshops. Both utilities are resolute that this change is sensible and conforms to the spirit of the procurement decisions.

Both PG&E and SoCal have replaced their previous supply and capacity protocols with the service level protocols. Both have retained the end-use priority scheme. SDG&E has retained the supply curtailment pattern outlined by DRA above. SDG&E's capacity curtailment protocol follows the service level outline.

The net effect of PG&E's and SoCal's change to supply curtailments is that utility procured gas will not be curtailed first. Instead, Service Level 5, customer-owned gas is curtailed first, then each of the other service levels are curtailed in reverse priority, according to the particular conventions within each service level. Service Level 2 curtailments are the last in the series. In this level, customers are curtailed pro rata by end-use priority. Utility gas (core subscription, Service Level 2) and customer-owned gas transported under Service Level 2, is curtailed equally.

When the Commission first changed the supply and capacity curtailment rules, effective in 1988, curtailments were rare events and capacity was not scarce. Now, the utilities face capacity constraints. Additional pipeline capacity is planned, but is currently unavailable. Recently, some supplies have chased prices eastwardly, when the country's winters have been harsh, or have never arrived due to wellheads freezing. On other occasions, curtailments occurred due to mechanical problems. As under a "supply" curtailment, when this happened the end result was the same -- more demand than available supply.

Since 1988 the Commission has hosted annual sessions dealing with supply curtailments. In 1989, SoCal's core supply was at risk due to the "Siberian Express". It snowed in Los Angeles; wellheads froze in Oklahoma. SoCal had to rely on customer-owned gas for supplies to the core. Last year, PG&E's affiliate, PGT system lost a day's worth of gas. Supplies were scarce. The Commission was required to provisionally allow the utility to confiscate customer-owned gas in order to provide gas to the core. When December's cold weather moved into the central part of the country, the curtailment became a capacity curtailment. The definitions of a supply and a capacity curtailment became blurred. Again, the end result was that there was more demand than available supply.

CACD believes that the curtailment rule changes of the procurement decisions should be adopted to apply to all curtailment conditions, whether supply-caused or capacity-caused. These rules will change again, under capacity brokering. However, for the present time, CACD believes that a single curtailment scheme using the adopted service level rules is the correct choice. It will be clear and relatively easy to administer.

In addition, CACD recommends that the Commission drop the requirement of the utilities to distinguish between a supply and a capacity curtailment, because the cause of the gas delivery problem is not readily known. A curtailment should be defined as a condition where either a supply or capacity constraint interferes with normal deliveries of gas.

CIG raises the additional issue of a localized restriction on the delivery of gas, where a shortage on the interstate system negatively impacts the delivery of California produced gas. This issue was addressed in the May 9th workshop and an acceptable solution emerged. PG&E, Capital Oil Corporation, and SunPacific Energy Management agreed to adopt the following language to forestall this problem:

> "Transportation of customer-owned, California produced gas shall not be curtailed due to deficiencies or other problems affecting the delivery of natural gas from the interstate pipeline system."

CACD recommends that the Commission adopt the quoted agreement above to insure that California gas can flow even under the condition of an interstate pipeline curtailment.

Diversion of Customer-Owned Gas

CIG protests that SoCal's modified Curtailment Rule (Rule 23) does not provide for compensation of customers in the event that their own gas supplies are diverted under a Commission declared supply emergency. CIG also protests SDG&E's Curtailment Rule (Rule 14) for the same reason. CIG argues that there is no basis to delete this long-standing provision.

Discussion

SDG&E agrees with CIG and states that this oversight will be corrected. SoCal did not reply. CACD noticed that this previously adopted language was not present in any of SoCal's current tariffs. Both SDG&E and SoCal should add language comparable to that used by PG&E in its Curtailment Rule 14:

> "In the event customer's gas is diverted, customer has two options for make-up by Utility, either:
>
> 1. Replacement of the gas on a therm-for-therm basis; or,
>
> 2. Reimbursement for the diverted gas, paying the customer a value-based price, tied to the customer's alternative fuel price."

Also, CACD notes that some new service options have been added to the gas restructuring program in the past few years which are present in the PG&E Rule 14, but are absent from SoCal's proposed Rule 23. These services are Balancing Services, Storage Services and Interutility Service. Each has a 'priority' with respect to the delivery of gas and available capacity. CACD recommends that SoCal add these as-available services to the protocol of Rule 23 in order to clarify when and under what conditions these services will be curtailed.

Capacity Curtailment Protocol

DRA protests that PG&E's Rule 14 does not conform to D.90-12-100 for curtailment of service. According to this decision, curtailment of Service Levels 4 and 5 are based on price and curtailment of Service Levels 2 and 3 are based on end-use priorities.

PG&E responds that curtailment of service shall conform to D.90-02-022, which changed curtailments to Service Level 3 according to price, with the highest paying customer curtailed last. For Service Level 3 customers paying the same rate, curtailments will be made according to end-use priorities. PG&E states that it will modify its Rule 14, Section E and H.4 accordingly in its supplemental filing.

<u>Discussion</u>
In the workshop held May 9th, CACD became aware that the utilities and the cogenerators have a problem with respect to this change. CACD agrees that compliance with D.90-02-022 requires this change, but this decision has an inconsistency and should be changed to accommodate a complete resolution of the issue. The decision at page 2 reasons that:

> "We reiterate here that D.90-12-100 has already clarified D.90-09-089 to state explicitly that within Service Levels 4 and 5, no cogeneration volumes will be curtailed before UEG volumes within the same transmission rate and service level. To the extent that Shell Western and CSC believe they have identified a problem with Service Levels 2 and 3, we disagree; any problem related to curtailment based on price paid does not exist for service levels where curtailment is determined according to existing end use priorities. We will clarify our rules in this regard (see page 7 of Appendix A.)"

However, what was adopted was a change to Service Level 3 from end-use priority to curtailment by transport price paid, with ties settled by the end-use priority system. The issue here is that cogenerators would possibly pay a lower transport rate than the UEG within the Service Level 3, and as a result, could be curtailed before the UEG, or due to the fact that the cogenerators are classified as P3A, and some UEG load is classified at the higher end-use priority 3, some load could be curtailed before the UEG load, and this would contradict the Public Utilities Code. Decision 90-02-022 accommodated this issue with the added statement for Service Levels 4 and 5 that:

> "For Service Levels 4 and 5, UEG and Cogeneration load with equivalent transmission rates shall be combined to determine a pro rata curtailment volume in relation to other non-core customers. However, while the UEG and Cogeneration volumes are combined to determine a pro rata allocation, all the actual curtailment so allocated to the two classes of customers shall be imposed against the UEG volumes until they are exhausted, so that no Cogeneration volumes will be curtailed before any UEG volumes within the same transmission rate and service level."

CACD recommends that at least for consistency, that the Commission adopt the pro rata curtailment mechanism for application to Service Level 3, UEG and cogeneration customers.

<u>ALTERNATE FUEL CAPABILITY</u>

<u>Alternate Fuel Capability and Requirement</u>
In its protests to each of the utilities' filings, CIG challenges the continued need to require noncore customers to have alternate fuel capability (standby fuel) as a condition of service under any of the new service levels. CIG argues that alternate fuel

capability requirements are inconsistent with the Commission's adopted policies, given the Commission's reliance in D.90-09-089 upon price and other economic factors as the basis for a customer's service reliability choice, and with its clear notice to noncore customers that they assume the risk of service curtailments under their chosen service levels.

CIG adds that when the utilities or the Commission insist that customers maintain an alternate fuel capability as a condition of eligibility for service, they not only place an undue economic burden on the industry forcing unnecessary capital investments, they also invade the decision-making prerogatives of the customer. CIG argues that a customer may find it more economical to curtail production in the event of a service interruption than to invest capital in storage tanks and other alternate fuel facilities.

CIG believes that the standby fuel requirements should be eliminated and replaced simply with a statement that the customer assumes all risk of curtailment. CIG concludes that neither the gas utilities nor their regulators have any duty to protect customers from the consequences of their service elections. "If a customer chooses a level of service that is relatively less reliable in order to minimize its energy costs, the customer itself must bear the responsibility for the choice."

CIG further argues that the utilities' requirement that the customer sign an affidavit attesting to his familiarity with curtailment procedures is also unnecessary. The utility and the customer are bound by the provisions of the Commission-approved tariffs, and the execution of an affidavit has no added value.

SDG&E agrees with CIG that customers have notice of and are bound by its filed tariffs. SDG&E offers to remove the affidavit requirement from its tariffs, but does not respond to the removal of standby fuel from the service conditions. SoCal replies that CIG's position is not supported by Commission orders, and that instead, the Commission has continued to rely on the existence of alternate fuel capacity as a distinguishing factor between core and noncore customers. SoCal admits that there may be some merit to CIG's policy argument, but that it is concerned that customers actually curtail when they are required to do so. Citing past experience, SoCal recommends not removing the alternate fuel condition for attaining noncore status until it has improved tools for enforcing curtailment. PG&E agrees with CIG and states that there may be reasons to eliminate this provision, especially in light of environmental concerns. But, PG&E suggests that this issue needs to be addressed by the Commission under another proceeding.

<u>Discussion</u>
The California Industrial Group, the California League of Food Processors, and the California Manufacturers Association (CIG) pose a persuasive argument that it is appropriate to remove the continued requirement that noncore customers have alternate fuel

capability as a condition of service under any of the new service levels. CIG urges the Commission repeal this requirement, stating that to do so is appropriate under the new rules and also meets the demands of changing air quality standards, which will be strictly applied in the near future. This issue is appropriate to this proceeding, but does affect other proceedings, as discussed below.

Alternative fuel capability has been required as a condition of service since the early 1980s. Customers at that time were installing switching fuel systems to accommodate escalating oil prices with fixed gas costs. This avenue provided a means where the customer could achieve economic goals by installing expensive equipment and maintaining reserve supplies. The utilities could rely on these customers to switch to oil, if gas became scarce. They became known as "interruptible" customers, and as such, received cost benefits for accepting less reliable service.

To unilaterally adopt this proposal without unraveling all of the costing methodology underlying the customers' rates would be inappropriate. Some large core-commercial P2A customers, who under the restructuring rules, have been allowed to be reclassified as noncore customers providing they meet particular economic feasibility tests, need to be considered. Also, all of those P2A customers desiring to be re-classified as noncore customers in order to reap the economic benefits of a lower transport rate, need to be allowed the option to choose interruptible transportation with the inherent risks of curtailment.

The P2A core customers currently pay greater transport costs under the adopted cost allocations. Their expected throughput drives the cost responsibilities of their class. Should they be relieved of this classification, a number of other core customers will be left responsible for the added expenses of their migration to the noncore side. This class otherwise should be allowed to opt for lower service.

A number of customers with alternative fuel capability, having facilities installed and operating, with standby fuel available, are in jeopardy of losing permits to burn their fuels due to air quality rule changes. In another instance, Mobil Oil in Bakersfield has been allowed to expand its operations under the condition of the local air quality board that it use only natural gas.

The environmental time has come to repeal the alternative fuel requirement, at least for those customers having installed facilities. For customers that have met the economic feasibility test performed annually by the utility, CACD has no simple answer. Similarly, a number of these potential core-to-noncore migrants exist in SoCal's territory with pending applications, and desire to cross-over-the-line from core status to noncore status.

CACD recommends that those customers who currently maintain alternative fuel capability and storage, and who are willing to curtail, be identified as a grandfathered group qualifying for the removal of the alternative fuel capability requirements.

Meanwhile, those P2A customers qualifying under the annual economic feasibility test of D.88-03-085 should be allowed to continue to establish their eligibility on an annual basis, as a second, grandfathered group. This grandfathering should also be extended to those customers with pending applications, which have passed the economic feasibility test. Both groups should be allowed to qualify for the program, but the line should be drawn at the August 1 deadline. Those customers missing the deadline may participate in the core aggregation program, until the cost allocation issue is resolved.

To resolve the group of P2A customers missing the deadline, utilities should maintain a list, identifying these customers and their historical volumes. This list shall constitute a throughput forecast class to be addressed in the OII 86-06-005 for Long Run Marginal Costs and/or the utilities' next cost allocation proceedings.

CACD has discussed this issue with the utilities for additional information, to be assured that providing this relief is prudent. However, achievement of a full, nondiscriminatory program for all customers requires a cost allocation proceeding to address the shifting throughput and cost responsibilities these customers currently have. Both noncore and core customer rates will be affected when this occurs.

CACD recommends that the following caveats be adopted to ensure compliance. First, any one of these customers may fail to curtail when asked to do so. To protect against abuses and irresponsible actions impacting on other customers, CACD recommends adoption of a penalty similar to that adopted under the core aggregation program under D.90-02-046 of $1/therm, if a customer under this program fails to curtail.

Utility enforcement is difficult. Therefore, any penalty funds not applied to replace the used gas, should be deposited into a tracking account established to install electronic metering devices for this class of customers. In the meantime, the price of entry to this program should be the installation of an electronic meter at the customer's expense, for compliance monitoring.

<u>Failure to Curtail - Backbilling</u>

CIG objects to the curtailment backbilling rules of the utilities, which state that the utility reserves the right to backbill a customer if the customer does not make a reasonable effort to discontinue gas usage when requested to do so. CIG also protests SDG&E's core subscription schedule (Special Condition 17 of Schedule G-CORE) that proposes to rebill the customer for the previous twelve months under the applicable "core" rate schedule (P-1 and P-2A) service during that period if the customer fails to curtail.

CIG believes that backbilling is too harsh a penalty and also a legally questionable practice. This would be especially true in the situation where a customer's failure to discontinue gas usage may extend only for a few hours or days. CIG suggests instead that the utilities impose a 50 cents per therm penalty for gas usage during a declared curtailment. CIG believes that this penalty would serve as a powerful economic disincentive towards preventing gas usage during curtailment periods.

PG&E agrees that a penalty rate would be more effective. PG&E proposes to use the $1/therm penalty that was authorized by the Commission as a penalty rate for balancing service taken by core customers when balancing services are otherwise curtailed. SDG&E is amenable to discussing this issue in workshops. SoCal has concerns about this problem.

Discussion

In conjunction with recommendations under alternative fuel capabilities, CACD recommends adopting the $1/therm penalty for customers which fail to curtail when requested to do so. This should provide a deterrent to gas usage by interruptible customers during curtailment periods.

BALANCING

Minor & Unintentional Imbalances

IP and CIG object to PG&E's use of the phrase "minor unintentional imbalances" referring to differences between gas deliveries and customer consumption. IP and CIG state that these words are unnecessary and ill-defined. IP is concerned that they provide PG&E with a license to withhold balancing services based on unstated factors.

PG&E claims that its proposed tariff is reflecting the Commission's intent in D.90-09-089, that balancing service promote well-planned nominations by customers. PG&E further states that customers have an obligation to procure and deliver to PG&E the quantity of gas supply which they expect to use in their plant each day. Therefore, PG&E expects any imbalances to be both unintentional and minor.

Discussion

CACD believes that it is difficult to prove that a customer deliberately intended to create an imbalance. PG&E's use of the phrase "unintentional and minor" in this schedule is unnecessary and should be removed.

Excess Imbalances
IP and CIG protest PG&E's prohibition of trading excess imbalances, or, those imbalances greater than the 10% threshold. CIG recommends that in order to minimize the likelihood of penalties, customers should be allowed to trade any imbalances. IP suggests that customers should be permitted to trade any imbalances so long as the trade moves their imbalances towards zero, instead of "excess imbalances" beyond the 10% threshold, as provided in the tariffs.

PG&E responds that the 10% threshold provides a cushion if any adjustments must be made to the final gas delivery volumes from the production area. Deliveries within the 10% threshold are not subject to change; however, they are carried forward and considered to be the first transaction in the next month. Trades of imbalances do not need to be finalized until the end of the second month. If the 10% threshold quantity was subsequently traded, an ongoing series of adjustments would occur, possibly resulting in trades of gas that otherwise would not have been necessary.

Discussion
D.90-09-089 ordered utilities to adopt a balancing program for noncore customers. It further adopted a 10% tolerance band for such imbalances. D.90-09-089 did not specifically define an "imbalance". In PG&E's balancing service schedule (Schedule G-BAL), "excess imbalance" is the volume of gas that exceeds the allowable 10% tolerance and is defined as the difference between the tolerance band and "cumulative imbalance". "Cumulative imbalance" is then defined as the difference between actual monthly deliveries and usage, adjusted for previous imbalances.

Based on PG&E's definition, a customer may trade only its "excess imbalance", which means that the customer may take action that will bring it back within the allowable 10% tolerance calculated for the subsequent month. The customer may not trade any volumes of gas within the 10% tolerance band. CACD believes this limits the capabilities and flexibility of the trading procedure. Decision 90-09-089 provided that customers should be allowed to trade imbalances as long as it does not complicate utility operations. PG&E should allow imbalance trading within the 10% tolerance band.

Trading Standards
IP protests that PG&E requires "approval of all trades" but does not set forth standards for its withholding approval. IP believes that PG&E will be informed of all the trades and the trades must conform to the rules in the schedule, therefore, a separate, undefined, PG&E approval is unnecessary.

PG&E claims that its approval of the trades will be based on the rules in the tariff. PG&E will not recognize a trade unless it conforms to the rules in the tariff.

Discussion
PG&E's approval of all trades requires that the imbalance trading form be submitted and that PG&E verifies that the trades are valid customers and amounts. CACD recommends that PG&E retain its statement that it requires approval of all trades.

Imbalance Trading Form
IP and CIG request that PG&E provide an "Imbalance Trading Form" to be used to confirm trades. CIG also requests that PG&E provide more information regarding its electronic bulletin board, that will be used in tradings.

PG&E replies that it plans to facilitate trading through an electronic bulletin board and it will also provide a form once use of the bulletin board is defined. PG&E further states that such a form will contain the customer's name, account number, imbalance quantity, calendar month in which imbalance occurs, and an authorized signature for each party involved in any trading.

Discussion
PG&E's balancing tariff refers to a trading form, but as IP has pointed out, such form does not exist. PG&E, however, seems to have established the details of such form and knows what it will contain. PG&E should submit an advice letter outlining its electronic bulletin board and should also submit a trading form for Commission approval.

Imbalance Trading Program Costs
DRA protests the balancing provision in SDG&E's Schedule GTCG, stating that it should comply with D.90-12-100 (Appendix, page 9). DRA suggests that Special Condition 22's last sentence should read:

> "If the utility chooses to do so, related costs shall be recovered solely, if at all, from participants in the trading program."

Discussion
SDG&E's statement has "....no related costs....". SDG&E replies that it will file revised tariffs to correct this error. CACD agrees and recommends that SDG&E reword Special Condition 22 of Schedule GTCG to state that related costs may be recovered from participants in the trading program.

Imbalance Notice
CIG protests that more details are needed on the timing of SDG&E's imbalance trading procedure as described in paragraph B.3 of the proposed rule (A.L. 744-G). CIG recommends that the customers be provided with at least 20 days from the date of the notice of any imbalance to make trades of imbalance.

SDG&E states that its trading program will be simple. Its trading program is defined in Exhibit A, Attachment 1 of its Natural Gas Service Agreement. SDG&E states that it is not opposed to CIG's recommendation that the customer be provided at least 20 days from the date of notice of any imbalance to make trades of imbalance.

<u>Discussion</u>
SDG&E's Exhibit A, Attachment 1 to its service agreement is a "Transportation Trading Form". The customer completes the form, which identifies his participation in the program. The procedure is that the customer sends a FAX to SDG&E, notifying the company of an imbalance it wishes to trade. The company then assembles a list of participants and provides this list to all other program participants. The form indicates that the participant agrees to notify SDG&E in writing of any successful trades prior to the next, regular scheduled meter read. CACD believes that SDG&E's proposed trading program will work, but is concerned that the information may not be timely enough for a customer to achieve a trade and still avoid a penalty. CACD recommends that SDG&E establish a "simple", PC-based bulletin board that customers can access by a personal computer and a modem. This would provide a faster resolution of the trade than reliance on a mailed list.

<u>Imbalance Trading Period</u>
DRA protests SoCal's Rule 30, Transportation of Customer-Owned Gas, because it fails to set a time limit on the trading period. DRA notes that it is unclear if the imbalance trading is restricted to imbalances within the same timeframe.

SoCal clarifies that it was its intent to have Rule 30 state that only those imbalances occurring in the same time period are eligible for trading.

<u>Discussion</u>
CACD suggests that SoCal reword its Rule 30 to clarify that imbalances occurring in the same time period are eligible for trading. SoCal should also define the term "time period".

SERVICES

<u>Sales of Excess Core Gas</u>
Indicated Producers protest the absence of language outlining the D.90-09-089 restrictions on the sale of excess core gas supplies. The Commission authorized the utilities to sell excess core gas supplies, when necessary, to avoid contractual penalties. IP states that in doing so, the Commission recognized that without prescribed limits, the utilities' sales of excess core portfolio gas supplies could circumvent its decision to eliminate the utilities' noncore gas portfolios. IP adds that among the restrictions ordered was the requirement that the utilities may

not use their firm interstate transportation capacity rights to transport the excess core gas sold to others.

CIG argues that the language in PG&E's proposed tariff sheets fails to reflect the provisions of the settlement and D.90-09-089. CIG states that PG&E's tariff should include the terms of the Settlement under which utilities may sell excess gas:

1) only if necessary to avoid the incurrence of reservation fees, inventory charges, or take-or-pay penalties;

2) only through a sealed bid procedure; and

3) only within the production basin.

CIG further requests that the language regarding sale of excess core gas to noncore customers express that the sales must take place either at the point of receipt into the interstate facilities or within the production basin for the gas supply in question.

PG&E responds that it does not foresee sale of excess core gas supply in order to avoid contractual penalties and, therefore, no terms and conditions have been provided, other than sales of excess core gas to SoCal and SDG&E under its interutility tariff.

SoCal replies that it is not clear from D.90-09-089 that any language is required in the tariffs regarding sales of excess core gas. SoCal says that its original intent in proposing the ability to make sales of excess core gas supplies, was to sell the gas to customers outside of its service territory (and probably outside of California) or possibly for resale by an unaffiliated party in California. SoCal questions if it is proper to have California tariffs cover a potential sale that is made outside California for consumption outside California, but remarks that the decisions have apparently left open the possibility of sales of excess core supplies to California end-users, though title would pass outside California. SoCal believes that the jurisdictional issue needs further consideration and that it is unclear whether it is appropriate to tariff the service with the CPUC.

SoCal adds that it intends to abide by the terms of the Commission's decisions on such sales. SoCal concludes that there is no apparent need to place this language in the tariffs for such sales are subject to reasonableness review.

<u>Discussion</u>
The adopted Commission rule regarding sales of excess core gas supplies states:

> "The utilities shall sell excess core gas when required in order to avoid contractual penalties. The sales shall be conducted by way of sealed bid. The utilities may not use capacity rights to transport excess gas sold off-system.

> Neither may the utilities use their interstate capacity rights to transport excess gas sold on-system unless the rights are exercised by a noncore customer holding such rights through a FERC-approved capacity brokering program.
>
> PG&E may sell excess core gas to SoCal and SDG&E to meet their core customer requirements."

Although the utilities may not foresee the need to exercise this option in the near future, they should develop procedures and a tariff consistent with the rules for curtailment and transportation to perform this service should it become necessary. CACD recommends that the utilities submit separate advice letters outlining a program and bidding rules for sales of excess core gas to comply with the procurement decisions.

<u>Interutility Gas Sales</u>
TURN argues that the language used in PG&E's Interutility Transportation Service, Schedule G-INT, implies that an interutility fee will be included in the price when PG&E sells excess core gas to SoCal and SDG&E. TURN argues that no interutility fee is authorized or appropriate under these circumstances. TURN asserts that it can not be determined which interutility rates to apply because of the commingled nature of system supply. TURN adds that the gas that PG&E must sell-off on a daily basis for operational reasons is already in the service territory and requires no further transportation. TURN proposes to add an entirely separate tariff for sale of excess core gas under the sealed bid and operational requirement conditions.

PG&E confirms its interutility tariffs include an interutility transportation rate as well as a sales price to SoCal and SDG&E, and claims that this was done for simplicity. PG&E states that its interutility tariff proposes to sell excess core supply gas to SoCal and SDG&E at the Core Subscription procurement charge plus an applicable interutility rate. PG&E cites D.87-09-027 which adopted the interutility rates.

PG&E disagrees with TURN's statement that the excess core supply in the pipeline requires no further transportation, and states that, for example, PG&E may have to transport gas from Topock, a receipt and delivery point, to Kern River in order to deliver gas into the SoCal system. Due to this, PG&E believes that it is appropriate to recover the costs that were operationally incurred to deliver the gas. PG&E explains that the 2 day advance nomination on the El Paso system and a 1 day advance nomination on the Pacific Gas Transmission (PGT) system inhibit PG&E's ability to exactly match system demands and that sales of excess supply to the Southern California utilities becomes operationally necessary.

PG&E argues that sales of excess core gas to SoCal and SDG&E are interutility transfers and that an interutility rate is appropriate. PG&E offers to include language that these sales may be made "as a result of day-to-day operating conditions", but adds that it is not practical to develop a sealed-bid program due to the short timing of these sales. However, for the sale of excess gas to noncore customers other than SoCal and SDG&E, PG&E may develop a sealed-bid program in the future.

Discussion
Sales of excess core gas, as described by PG&E under its interutility tariff, is really a description of PG&E's day-to-day balancing needs and is also a service relating to the Mutual Assistance Agreements between SoCal and PG&E. CACD recommends that PG&E maintain its description of excess sales gas to SoCal and SDG&E under its interutility tariff to accommodate the daily balancing operations, but that it rename and redefine these types of sales, making the distinction that this service is different from its program to provide sales of excess gas under a separate bidding program, available to all bidders. All utilities should submit a separate tariff to identify the excess core gas sales program and procedures.

Core Subscription Term
DRA and SDG&E requested SoCal to clarify the term commitment for core subscription service outlined in the tariff Schedule GN-71 for service to SDG&E. Both state that SoCal has inserted a one year term commitment for core subscription service, rather than a two-year commitment as was mandated in D.90-12-100.

SoCal states that this is an error caused by carrying over existing provisions for core-elect procurement service. SoCal agrees that it should be modified to specify two years to be consistent with current Commission orders.

Discussion
The adopted commitment term for core subscription service is two years. The Commission will not revise this commitment period in anticipation of implementation of its capacity brokering program. However, the Commission may choose, in its decision on capacity brokering, to provide customers an option to proceed directly to capacity brokering arrangements. CACD recommends that SoCal modify its wholesale schedule for SDG&E specifying this to comply with the procurement decisions.

Full Requirements Customers
CIG argues that PG&E's full requirements customers should be able to take excess quantities under Service Level 2, even if they have not elected core subscription service.

CIG and Long Beach argue that SL-3 customers should be allowed to become "full requirements" customers. CIG cites the Settlement which stated that any customer with an annual contract could become a full requirements customer. CIG argues that retention of this option would facilitate the planning process for customers such as food processors which are unable to forecast their annual requirements accurately.

DRA protests SDG&E'S noncore transportation schedule, GTNC, which permits customers to be full requirements customers under Service Levels 3 through 5. DRA argues that authorization for SDG&E to procure gas for its noncore, non-UEG customers at all service levels does not mean the Commission authorized a "full requirements" option for Service Levels 3 through 5.

PG&E acknowledges that its firm transportation customers have operational limitations because they are required to nominate specific volumes. PG&E adds that it expects full requirements customers to match their historical profile, otherwise their service agreement will allow them to receive incremental transportation service under core subscription service or interruptible transportation service. PG&E agrees with CIG's argument that a full requirements option should be allowed under Service Level 3, and offers to change the tariff to provide a full requirements option for SL-3 customers. SoCal responds that the Commission's decisions only authorize a full requirements contract for SL-2 customers, but that it too supports an extension of the full requirements option to SL-3 customers.

SDG&E agrees that D.90-12-100 had no specific authorization to allow SL-3 and SL-4 customers a "full requirements" option. SDG&E replies that it was given authority to procure gas for noncore customers but with no explicit directions on how to do so. SDG&E argues that it needs flexibility to efficiently procure noncore, non-UEG gas at all service levels, and the "full requirements" option meets the needs of its customers. SDG&E states that DRA has not offered any alternatives nor given reasons why such an option should not be allowed. The Commission authorized SDG&E to procure for its noncore customers, and the "full requirements" provision in SL-3 and SL-4 is part of SDG&E's program to accomplish its procurement objective.

Discussion

The "full requirements" option of the Settlement and the procurement decisions provides that a Service Level 2 customer under an annual service level commitment, does not have to state an annual contract quantity, but is prohibited from using alternative fuels. Should the customer violate this prohibition, it is subject to an 80% use-or-pay penalty. The use of alternative fuel excepts curtailments, fuel system testing, and explicit, utility authorized use.

The procurement decisions adopted this option exactly as it was worded under the Settlement. What the decisions did not include was the footnoted definition of full requirements in the body of the Settlement. This states:

> "A 'full requirements' customer must commit to use of natural gas for his full fuel requirement during the contract period. This option does not require the customer to

purchase the utility's system gas. Customers may not split their requirements between this service option and any other."

It is clear that the full requirements service option was contemplated for firm Service Level 2 service only. What is not apparent is the reasoning for limiting this option to Service Level 2, when an "annual" service level commitment was required. A Service Level 3 customer must make an annual commitment as well. If a Service Level 3 customer commits to a year's interruptible service for all load, the utility can still manage its system without an annual contract quantity specification. The utility can rely on the historical use of the customer to plan for its capacity just as easily as for a Service Level 2 customer. The utilities support the extension of the full requirements option to the Service Level 3 customers and believe they can manage their systems without the annual contract quantity specification. However, without an annual commitment, system operations management could be jeopardized. CACD recommends that the Commission extend this option to Service Level 3, but with additional requirements.

The condition prohibiting customers from splitting their loads between service levels under the full requirements option is balanced with the non-specification of an annual contract quantity. This requirement serves to restrict a customer from gaming the service levels. If the full requirements option is allowed to Service Level 3 customers, this trade-off should be retained.

If a customer should burn alternative fuel under the Service Level 2, full requirements election, the utility's reservation for the expected capacity usage is wasted and such irresponsible action should be penalized. Similarly, if a Service Level 3, full requirements customer were to burn alternative fuel instead of using its reserved interruptible capacity, the capacity reserved for this customer would be idle. It is sensible to extend the Service Level 3, 60% use-or-pay penalty for burning alternative fuels to interruptible full requirements, Service Level 3 customers.

In the interest of providing flexibility under the new transportation structure, it is reasonable to extend the full requirements option to Service Level 3 customers in parity with the service level options. This will provide those customers unable to accurately forecast their requirements an option under interruptible service. CACD also recommends that the utilities incorporate the Settlement's footnoted definition of a full requirements customer to fully explain the additional conditions of service under this option. Finally, CACD sees no reason to also extend this option to any of the other service levels, as is proposed by SDG&E. To do so could subvert system operations and would allow customers to abuse the system. CACD recommends that the Commission adopt all of the identified provisions above, and require the utilities to amend their tariffs to accommodate these changes.

Long Term Transportation Service, Schedule GC-2:
CIG claims that under the last provision of PG&E's Schedule GC-2 (long-term transportation contracts) customers are given the option to increase their priority from SL-3 to SL-2 by paying one-half the volumetric portion of the rate applicable under this Schedule and one-half of the forecast equivalent rate under the customer's otherwise applicable rate schedule plus 1.2¢/ therm. CIG believes that the tariff language should be modified to provide that GC-2 customers must only pay one half the difference between their current total rate and the SL-2 total rate, plus 1.2¢/therm, in order to receive SL-2 status.

PG&E agrees with CIG that the language in Schedule GC-2 needs to be modified to more accurately reflect the provisions in D.90-09-089.

Discussion
The procurement decisions determined that customers with long-term contracts in existence on the effective date of the rules, and whose contracts do not specify otherwise, shall receive service at the contract rate Service Level 3 service. Customers could alternatively opt for Service Level 2 service at a rate equal to one-half the existing default rate and one-half the existing contract rate, plus a 1.2¢/therm surcharge. CACD recommends that PG&E change the language in its Schedule GC-2 to reflect that should the customer elect to have service under Service Level 2, that the rate paid is one-half the difference between their current total rate and the SL-2 total rate, plus 1.2¢/therm.

65% P-5 Limitation
CCC and CSC request clarification about which utility electric generation (UEG) end-use volumes (P2B, P3, or P5) are included in the application of the UEG 65% limitation in Service Levels 2 and 3 (SL-2, SL-3). This issue was mostly resolved by D.91-02-046, but CCC and CSC protest the fact that SoCal's tariffs do not specify monthly patterns in which the 65% limitation of UEG elections for SL-2 and SL-3 apply. CCC is concerned that other noncore customers could be excluded from transporting monthly volumes if the UEGs were not restricted to some monthly limit.

In response, SoCal states that historical seasonal usage patterns will be considered to establish UEG nomination limits. SoCal notes that no decision addresses whether the 65% limitation applies on an annual or a seasonal basis. In addition, SoCal requests clarification regarding the 65% limitation to Enhanced Oil Recovery (EOR) P-5 load served under existing long term contracts:

"Decision Nos. 90-09-089 and D.90-12-100 provided that all EOR P-3 and P-5 load served under existing long-term contracts would be placed in SL-3, with an opportunity to upgrade to SL-2. One rationale for applying the 65% limitation to EOR P-5 volumes in D.91-02-046 was that customers paying heavily discounted rates should not have an advantage in obtaining higher priority service. Therefore, the rationale of D.91-02-046 supports the interpretation that that decision intended to apply the 65% limitation on P-5 volumes in SL-2 and SL-3 to all EOR P-5 volumes, whether or not served under existing long-term contracts. However, D.91-02-046 did not explicitly amend the section of the procurement rules addressing long-term EOR contracts."

Discussion

Given the curtailments and constrained capacity on SoCal's system over the last few years, it is difficult to make a unilateral designation that UEG and EOR P-5 65% restrictions should be made on an annual or seasonal basis. The general rule has been to ensure core protection. If it is done on an annual basis, the P-5 customers will have more flexibility. If it is done on a seasonal basis, capacity constraints can be managed more effectively. Absent any better information, CACD recommends that the 65% limitation on P-5 UEG and EOR elections be based on seasonal usage to maintain predictable capacity requirements.

SoCal requests clarification on whether the 65% limitation on EOR P-5 loads also applies to EOR customers with long term contracts. CACD recommends that these customers be limited to the restriction as well. The Commission's initial objective was to provide these incremental customers with the opportunity to improve their priorities. Under the procurement decisions, this option is provided, but with the provision that such elections be restricted to 65% of their total demand. Under conditions of capacity constraints, it is unreasonable to allow any end-use Priority 5 customers any change from this restriction. To allow some EOR P-5 customers to elect all of their demand into higher service levels while limiting others is discriminatory. CACD recommends that the Commission clarify that the the 65% limitation on P-5 volumes in SL-2 and SL-3 applies to all EOR P-5 volumes, whether or not the customer is served under existing long-term contracts.

SAN DIEGO GAS AND ELECTRIC COMPANY SERVICES

SDG&E Noncore Procurement Authority

DRA protests Schedule GPNC (Natural Gas Procurement Service Service for Noncore Customers) which provides an interruptible procurement rate for Service Levels 3 through 5. The Commission authorized SDG&E to procure gas for these customers but it did not specify the basis for the procurement rate. It is unclear to DRA whether SDG&E should have two portfolios, core and noncore. DRA believes SDG&E's procurement rates and policy should be addressed in a workshop or written comments, and that the Commission should issue a ruling providing guidelines for SDG&E's procurement practices.

SDG&E agrees that D.90-12-100 lacked specific implementation provisions which are necessary to implement its noncore procurement. SDG&E has designed provisions which it believes are appropriate and included them in its tariffs.

SDG&E is in favor for a workshop on its procurement rates and policies. It also agrees with DRA's recommendation that a Commission ruling on guidelines for SDG&E's procurement practices is appropriate but only after a workshop and taking comments of interested parties.

Discussion

CACD has reviewed and has had detailed discussions with SDG&E about its proposals for portfolio construction. SDG&E's current gas portfolio consists of short-term supplies. SDG&E proposes to collapse its core and noncore portfolios into one portfolio with three subaccounts. The single portfolio will be made up of purchases from term agreements, storage withdrawals, spot purchases, and purchases made from other California utilities. The portfolio will have three different subaccounts and pricing methods:

> Core Embedded Price, where the gas destined for core customers, as adopted in SDG&E's cost allocation proceeding will be a 12-month forecast WACOG (weighted average cost of gas), with no more than one adjustment over the course of a year.
>
> Core Subscription Price, where the portfolio's actual WACOG of gas from all sources is lagged 30-days. The price will be adjusted monthly.
>
> Noncore Price, where the portfolio's monthly forecast WACOG for gas from all sources is posted. This price will change no more than twice each month.

The noncore service level choices eliminate the need for the portfolio switching ban adopted under the gas restructuring of 1988. Portfolio construction should abide by the previous decisions to provide a reliable and cost effective supply for customers. Should SDG&E procure core gas under a long term contract in the future, SDG&E must apply with the Commission for its approval. At that time, the Commission should address portfolio arrangements and construction. CACD recommends adoption of SDG&E's proposal, subject to future cost allocation and reasonableness review proceedings.

Core Subscription Service

CIG objects to SDG&E's core subscription schedule (GCORE). CIG argues that it should not refer to monthly volumes since this schedule applies to a two-year service commitment and use-or-pay obligations are based on annual commitments.

DRA protests Special Condition 4 of Schedule GCORE, which requires "full requirements" customers to use 100% of their annual contracted volume. DRA argues that this is not in compliance with D.90-12-100 because "full requirements" customers do not specify an annual contract quantity.

In addition, DRA argues that the use-or-pay penalty rate of 80% of the transmission rate as set forth in Special Conditions 4 and 5 are inconsistent with D.90-12-100. Schedule GCORE's total transmission rate is the sum of the procurement and transportation rates. The 80% should apply only to the transportation rate, but since the transmission rate is the sum of the procurement and transportation rates, the 80% applies to both the procurement and transportation rates. DRA argues that the take-or-pay penalty rate on procurement is 14% of the WACOG pursuant to D.90-12-100.

SDG&E agrees with CIG and DRA's objections and it will file revised tariffs correcting these errors in its Schedule GCORE. Also, SDG&E replies it will clarify the calculation of the use-or-pay penalty.

<u>Discussion</u>
CACD agrees with CIG and DRA's arguments. The procurement decisions provided for two-year annual commitments and an 80% use-or-pay penalty on the transportation rate of Service Level 2 elections, not the procurement and the transportation rates. CACD recommends that SDG&E file revised tariffs to comply.

<u>Noncore Procurement</u>
CIG objects to SDG&E's Noncore Procurement Schedule, GPNC, Special Conditions 5 and 9. CIG states that these conditions subject the customer to two take-or-pay penalties. CIG recommends that Special Condition 5 be eliminated. Special Condition 9 reflects the provisions of the recent gas procurement decisions, and CIG recommends that it should remain in the proposed tariffs.

SDG&E agrees and will eliminate its Special Condition 5 and retain Special Condition 9 in its tariffs.

<u>Discussion</u>
SDG&E's currently adopted Special Condition 5 refers to termination provisions where the customer terminates the utility's procurement service prior to the expiration of the contract. In such a case, the customer is liable to the utility for any excess procurement costs incurred by the utility due to the shortfall in the contracted purchases, unless the utility is able to avoid such costs.

SDG&E's Special Condition 9 refers to take-or-pay procurement obligations to which customers shall be subject if they elect procurement services of the utility. These charges shall be equal to the utility's average cost of gas, inventory charges plus any similar unavoidable costs. This condition also includes the take-or-pay penalty of 14% of the current WACOG of the utility's gas supply.

CACD agrees with CIG that Special Condition 9 reflects the provisions of the recent gas procurement decisions. CACD recommends that SDG&E delete Special Condition 5 and retain Special Condition 9 under its noncore procurement Schedule GPNC for compliance with the procurement decisions.

COGENERATION ISSUES

Notice

CSC states that PG&E's tariffs fail to comply with Commission's order in D.90-12-100 for they do not specify that cogenerators will be provided notice of the UEG's transportation elections or that cogenerators will have additional time to elect their own transportation services after notice is given. CSC objects to PG&E's omission of this under its Rule 1 definition of Open Season, and additionally requests that the notice include both volume and cost information. Although SoCal's tariffs allow cogenerators extra time beyond the end of the service level open season, CCC, CSC, and IP object to SoCal's omission of how cogenerators will be notified of UEG service level elections (GT-30, Special Condition 14; GT-50, Special Condition 17).

PG&E responds that under Schedule G-UEG, PG&E's electric department is required to provide notice to all customers taking service under Schedule G-COG of its transportation elections. PG&E believes that this will allow cogenerators the opportunity to match their service level choices to the UEG service level elections and therefore sees no reason to modify the definition of Open Season in Rule 1. PG&E states that in its future filings, Schedule G-UEG will be modified to reflect that the notice will be made five business days prior to the close of the open season.

SoCal acknowledges that the Commission has required such notice to be given, but requests that they not be required to specify the exact form of the notice (i.e. FAX, telephone call, letter, etc.). SoCal believes that specification in the tariffs of the type of notice to be issued is too fine a detail to add.

Discussion

Decision 90-12-100 ordered the utilities to provide cogeneration customers with at least five business days advance notice of UEG transportation elections prior to the cogenerators' deadline for electing transportation services. PG&E mailed notice in March 1991, far in advance of the closure of its open season. SoCal's

1991 open season has not closed yet, and its UEG customers have not finalized their service level choices.

To comply with the procurement decisions, the tariffs and rules should specify that cogenerators will be provided notice of the UEG elections. The tariffs should also specify that cogenerators will have five business days from the close of the open seasons to finalize their elections. The cogeneration notice should identify UEG volumes elected by service level and month, and should calculate the estimated transportation costs for these categories. Procurement cost information is proprietary and is not required on the notice. Notice may be made by any expedient means. The type of notice to be issued should not be required to be specified in the tariffs.

<u>Cogeneration Gas Allowance</u>

CCC argues that PG&E's and SDG&E's cogeneration gas allowances (CGA) are incorrect because the values are based on an Incremental Energy Rate (IER) rather than an Incremental Heat Rate (IHR). CCC states that D.90-09-043 requires that the CGA be calculated using an IHR. CCC also remarks that PG&E's IER in the proposed Schedule G-COG is based on a 1988 value, and that if the CGA were to be based on an IER, PG&E needs to update this value.

PG&E replies that the IER/IHR issue discussed in D.90-09-043 only applied to SoCal and was not intended to be a generic proceeding of statewide significance. PG&E believes that CCC's protest is without merit.

PG&E agrees with CCC that its CGA is not based on the currently adopted IER. PG&E states that the CGA currently being used is the most recent value approved by the Commission. PG&E adds that it has submitted advice filings to update the CGA and is currently awaiting Commission action. SDG&E agrees with CCC that the calculation of CGA should be based on an IHR to comply with D.90-09-043. It will file revised tariff sheets reflecting this correction.

<u>Discussion</u>

Although D.90-09-043 approved SoCal's use of an IHR, Resolution G-2738 adopts use of an IER value for PG&E. Resolution G-2946, adopting a methodology for SoCal's calculation of an IHR directs PG&E and SDG&E to revise their cogeneration tariff sheets, specifying the calculations of the CGA under the format adopted for SoCal. PG&E and SDG&E are also required to update their CGAs upon the conclusion of the relevant Energy Cost Adjustment Clause (ECAC) proceedings. Until the Commission considers this matter further, PG&E and SDG&E should file tariff revisions consistent with Resolution G-2946, issued April 24, 1991.

<u>Cogeneration Rate Construction</u>

CCC protests each utility's cogeneration rate schedule arguing that they do not specify how possible discounted UEG Service

Level 3, 4, and 5 rates will be accounted for in the cogenerator ratemaking process. CCC requests clarification of SoCal's proposed new rate methodology. CCC argues further that none of the tariffs comply with General Order 96-A (G.O. 96-A) standards for they do not insure that customers receive the information necessary to understand their rates.

SoCal disagrees with CCC. It states that cogeneration rates are based on forecast UEG rates, not actual or negotiated UEG rates and that none of the decisions under R.90-02-008 have ordered any change in this approach. SDG&E argues that its tariff schedules state the changes to be made and comply with the relevant provisions of the California Public Utilities Code and General Order 96-A. General Order 96-A does not require information allowing customers to predict future rates. PG&E responds that PG&E's only UEG customer is its own electric department. PG&E states that since it cannot negotiate a rate with itself (D.86-12-009, page 72, as modified by D.87-03-044, page 22), this concern is moot.

Discussion

The procurement decisions adopted the deletion of noncore demand charges and applied this to the UEGs as well. The effect of this collapsed the demand charges into a single rate. The UEG transportation rates are not negotiable. Cogenerators request information to understand the methods and calculations used by the utilities to refashion the UEG schedules. This is a reasonable request and CACD recommends that each of the utilities provide this information to the cogenerators. CACD also requires a worksheet from each of the utilities which details the proposed rate design changes to verify that the calculations comply with the currently adopted revenues, throughput, and cost allocations. CACD notes that PG&E's ACAP will be issued prior to the August 1 implementation date and that additional coordination will be necessary to insure compliance with the pending rate structure decision under OII (I.) 86-06-005.

Cogeneration Transportation Rates

CCC objects to PG&E's use of a UEG forecasted rate for cogeneration transportation rates instead of the currently effective UEG actual rate lagged 60 days. CCC states that this issue is currently being considered in PG&E's ACAP filing and PG&E may not use this rate methodology.

PG&E responds that this issue has been discussed in the OII 86-06-005 Rate Design Proceeding and is currently being litigated in PG&E's ACAP. PG&E states that it will comply with the Commission's decision on this issue.

PG&E responds that it has explained in I.86-06-005 that if its proposed forecasted rate methodology is adopted, cogenerators would pay the forecasted firm rate (or the default rate, including the customer charge, plus 1.2¢/therm) for firm service or the forecasted interruptible rate for interruptible service.

For cogenerators who split their loads, the UEG firm rate would be paid under Service Level 2 elections and the UEG interruptible rate would be paid under Service Level 3 through 5 elections. Any cogeneration transportation under Schedule G-COG is limited to the cogeneration gas allowance.

PG&E replies that if the forecasted rate is not adopted, then cogenerators opting for interruptible service would pay the 60-day lagged, UEG price for UEG deliveries under Service Levels 3 through 5. Likewise, cogenerators opting for firm service would pay the 60-day lagged, UEG firm service transportation rate. For cogenerators who split their loads, the firm portion will be priced at the UEG firm rate and the interruptible portion at the UEG interruptible rate.

<u>Discussion</u>
The PG&E ACAP decision is anticipated shortly. A decision under I.86-06-005 is also expected soon. Regardless of the final outcome of these decisions, cogenerators' transportation rate will be determined using a methodology similar to what exists. What is significant is PG&E's explanation of its current method with its proposed method and how a cogenerator's transportation rate would be calculated under firm and interruptible UEG service elections. This explanation is sufficient to allow cogenerators to make service level choices. CACD recommends that the utilities file detailed worksheets of the changes to be implemented under the PG&E ACAP decision and the OII decision as a part of the supplemental filings made to comply with this resolution.

<u>Cogeneration Declaration</u>
CCC objects to the provision under PG&E's cogeneration schedule that requires customers to sign a declaration that allows PG&E the right to monitor the efficiency of the system. CCC argues that this provision is beyond the requirements of the procurement decisions. CCC argues that the procurement decisions had nothing to do with efficiency monitoring or changes in the requirements for service under the cogeneration gas tariff.

CCC also is concerned that PG&E's proposed changes to the cogeneration declaration raise issues that are currently under consideration in an ongoing Commission proceeding. CCC requests rejection of the changes to the cogeneration declaration.

PG&E responds that its proposed modifications to the Schedule G-COG Cogeneration Declaration are consistent with tariff enforcement requirements under the Commission's codes and PG&E's existing G-COG tariff. PG&E states that customers not in compliance with the G-COG tariff, as with any other tariff, will be backbilled at the customer's otherwise applicable rate. PG&E adds that this authority is detailed in PG&E's gas Rule 17 and in CPUC Code 736. PG&E believes that the language used in the declaration is reiterated so the signing party is fully aware of the tariff requirement.

Discussion

PG&E's Advice Letter 1624-G, Exhibit E, Declaration of Cogeneration, requires that PG&E will be allowed to install any additional metering required to verify compliance with efficiency standards. It also states that in lieu of such installation, data should be submitted to PG&E.

CCC protested this requirement on the basis that PG&E's advice letter deals with an ongoing issue (Application 89-04-021), which addresses utility monitoring of cogeneration efficiency. On May 8, 1991, D.91-05-007 approved utility programs to monitor and enforce efficiency standards for third party power producers. This decision concluded that utility monitoring of qualifying facilities (QFs) does not contradict any federal statue or rule and is in the interest of California ratepayers. Decision 91-05-007 ordered utilities to implement their monitoring programs within sixty days of the effective date of the Decision. It authorized utilities to obtain annual operational data from cogenerators in order to monitor their efficiencies and assure compliance with FERC's standards.

Cogenerators are required, each year, to submit to PG&E operational data for the previous year. This data will then be evaluated by PG&E in light of FERC's efficiency standards. In addition, cogenerators are required to meet the requirement of Section 218.5 of the California Public Utilities Code. Installation of gas, electric, and steam meters may be necessary to obtain such data and verify compliance with the above standards. In light of this, CACD believes that the addition of the metering requirement to the Cogeneration Declaration is reasonable and necessary for compliance.

PG&E's proposed Cogeneration Declaration requires that the gas service will be rebilled for 12 months and all subsequent usage billed at the otherwise applicable rate schedule for a cogeneration facility that does not meet the efficiency standards outlined in PUC Code 218.5, until the cogenerator can demonstrate efficiency compliance again.

Decision 91-05-007, Ordering Paragraph 1 states:

> "Past payments shall be assessed beginning on the day the power producer failed to meet pertinent efficiency standards."

Therefore, CACD recommends that PG&E retain its backbilling language on its Cogeneration Declaration, to comply with D.91-05-007.

Cogeneration Priority

CCC and DRA protest that SDG&E's advice letter filing does not comply with the procurement decisions, for there is no statement outlining the Commission rule requiring that no cogeneration volumes will be curtailed before any UEG volumes within the same transmission and service levels.

SDG&E notes that the issue of cogenerator priority was more recently addressed by D.91-01-022. SDG&E states that its supplemental filing will incorporate the revised cogenerator/UEG curtailment rules of this decision.

Discussion

CACD recommends that SDG&E modify its Rule 14 concerning curtailments to incorporate the adopted provision requiring that no cogeneration volumes will be curtailed before any UEG volumes within the same transmission and service levels. This statement should also be incorporated into the cogeneration and UEG schedules.

WHOLESALE ISSUES

San Diego Gas & Electric

SDG&E protests SoCal's Schedules GN-71 and GT-71 for service to San Diego, stating that they are inconsistent with its long term contract and they reduce its transmission service to interruptible status. SDG&E requests that SoCal be required to file a revised tariff schedule GT-71 which clearly states that service under the SDG&E Contract is to be provided at SL-2 or better, at the rates and charges set forth in the Contract. SDG&E adds that if the "special conditions" currently set forth in SoCal's Schedules GT-71 and GN-71 are contained in the revised Schedules, it must be clearly stated that these apply only to service beyond the contract.

SoCal responded to SDG&E's protest stating that most of the concern is that the tariff sheets are not consistent with the terms of the long-term service agreement. SoCal agrees that the Commission's intent in D.90-09-089 was to leave that contract in force.

SoCal replies that it has been meeting with SDG&E to resolve the concerns raised in its protest, and believes it has reached agreement with SDG&E on how to modify the tariff sheets applicable to SDG&E so as to be clearly consistent with the terms of the SoCal-SDG&E service agreement. SoCal hopes to be able to file these revised tariff sheets with the Commission shortly.

Discussion

SDG&E's protest was made prior to issuance of D.91-02-022 and D.91-02-046 which resolve a number of wholesale issues. Some of SDG&E's concerns have been satisfied through SoCal's compliance with its ACAP and attrition-related filings, also completed subsequent to its filing of Advice Letter 2009. If SoCal's supplemental filing does not settle SDG&E's concerns, SDG&E may protest SoCal's rewritten tariffs.

Southwest Gas

Southwest Gas (Southwest) initially protested PG&E's advice letter regarding the treatment of wholesale customers and concurrently petitioned for rehearing of D.90-12-100 on January 22, 1991. Most of Southwest's concern has been resolved by D.91-02-022.

Core Load

Southwest argues that the tariffs fail to provide PG&E wholesale customers with the ability to transport gas from independent suppliers to serve both core and noncore loads. According to Southwest, PG&E's tariff offers two options to wholesale customers for the purchase of core customer gas.

The first option is to elect core subscription service. This service reserves pipeline capacity proportional to the capacity reserved for PG&E's own core load. In other words, PG&E will reserve the capacity, but the customer will only be able to use it by subscribing to the core subscription service.

The second option is to request capacity under Customer Identified Gas Service, which has the 450 MMcf limitation. Southwest believes that PG&E's tariffs do not address the Commission's decision on the core transportation issue and requests modification to the tariffs to include the full range of service options established by the Commission.

Discussion

Decision 90-12-100 ordered PG&E to allocate transportation access to wholesale customers' core loads on the same basis as it allocates transportation access for its own core customers' load. Since PG&E reserves capacity for its own core customers' load outside the 450 MMcf limit of the G-CIG schedule, then PG&E's wholesale customers are entitled to obtain their reserved capacity access proportional to their core load outside of the 450 MMcf limit and should not be forced to elect service under core subscription or customer-identified gas schedules (G-CS or G-CIG). PG&E should modify its wholesale Schedule G-WRT to include this requirement for compliance with D.91-02-022, which provided Service Level 1 core transportation service to wholesale customers.

For noncore loads, PG&E is required by the procurement decisions to provide the option of servicing the wholesale customers' noncore customers directly or by securing capacity on behalf of the wholesale customer for its noncore customers. PG&E's supplemental filing provides for this option.

Demand Charges

Southwest protests PG&E's wholesale schedule (G-WRT), requesting that the foundation for PG&E's demand charges be investigated and clarified to assure that they represent the appropriate service levels. In addition, Southwest requests clarification on the treatment of demand charges for a wholesale customer who avails itself of unbundled transportation service options.

PG&E responds that cost allocation and revenue requirements for all wholesale customers are based on customer load profile and not on service level. PG&E replies that as a consequence, the wholesale demand charge calculations are not affected by a change from Service Level 2 to Service Level 1.

Discussion
Decision 90-09-089 eliminated demand charges for noncore customers and D.90-12-100 eliminated demand charges for UEG customers. None of the procurement decisions eliminated demand charges for wholesale customers. PG&E's wholesale demand charges should align with the forecasted throughput and costs of its pending ACAP decision. In addition, wholesale rate design issues are being considered under I.86-06-005. Both proceedings have pending decisions. When its compliance filings are made, PG&E should attach detailed tables showing the changes between the January 1, 1991 attrition filings to those changes ordered under the ACAP and the OII, comparing the previous wholesale rates and demand charges to the new values. If Southwest still has questions and concerns about the calculations, CACD suggests that it contact the CACD Energy Branch.

The City of Long Beach

The City of Long Beach Gas Department protests a number of items present in the revised SoCal Schedule GN/GT-70 for wholesale service and characterizes the schedules as materially inferior to the service currently provided and contrary to Commission decisions and policies.

Rate Design
Long Beach first protests the rate design change made by SoCal, which combines the demand and volumetric charges into a single volumetric rate. Long Beach argues that this is SoCal's proposed rate design in another, pending proceeding, is not subject to the procurement OIR, and has not been adopted by the Commission. Long Beach requests that SoCal replace its proposed rate design with the adopted ACAP rate design until the anticipated decision is rendered in Phase II of SoCal's ACAP.

SoCal replies that it did not discriminate against Long Beach, changing only their rates into a single volumetric charge, but that it did this for its other customers as well. SoCal states that the rate design shown in Advice Letter 2009 was intended only as a "place-holder" until the Commission issues a decision in the Phase II proceeding.

Discussion
CACD notes that on March 13, 1991, the Commission issued D.91-03-031 which adopted SoCal's original ACAP forecast for Long Beach's UEG demand. Decision 91-03-031 added that any further

proceedings regarding Long Beach's rate design proposal in A.90-03-018 "should await a decision of wholesale rate design issues currently being addressed in I.86-06-005". A decision in I.86-06-005 is pending. CACD recommends that SoCal file the monthly demand charges and volumetric charge applicable to Long Beach as authorized by D.90-11-023 and the attrition filings and adopted by D.91-03-031. SoCal should make an additional filing to incorporate any changes resulting from the OII, and clearly detailing in workpapers the changes from January 1, 1991 through the OII.

<u>Noncore Customers</u>
Long Beach protests that SoCal's proposed tariff does not address the case of some of its customers that want to nominate their full requirements into noncore Service Level 2. It asks if SoCal will treat Long Beach's nomination on behalf of such customers as full requirements, even though its entire noncore load is not nominated. Long Beach states that if this is not done, its customers will not have the service options that SoCal's customers will have. In addition, Long Beach seeks clarification of how its new customers will be accepted into SL-2 service.

SoCal responds that the Commission did not address these issues in its decisions. SoCal recommends that to solve these problems, Long Beach should notify SoCal of the historical requirements in the aggregate of those of Long Beach's customers who want SL-2 full requirements service, and SoCal would then provide SL-2 service to Long Beach in sufficient volume to meet these customers' full requirements. As a condition of this treatment, SoCal would require Long Beach to disclose historical consumption data of its customers selecting SL-2 full requirements service. Also, SoCal requests that Long Beach would have to agree to provide consumption data for its noncore customers on a current basis after implementation of this process so that SoCal can enforce equal treatment between wholesale and retail customers.

<u>Discussion</u>
Long Beach and all wholesale customers were provided with options to have service parity with both SoCal and PG&E. Decision 90-12-100, p.4 states: "we also agree that the wholesale utilities should have the option of serving their noncore customers directly or permitting those customers to participate directly in the gas utility programs". CACD believes that Long Beach and SoCal can negotiate fair terms consistent with the procurement decisions. Long Beach may appeal to the Commission, if negotiations become stalled or contentious.

<u>Interstate Pipeline Access</u>
Long Beach questions the statement in SoCal's proposed tariff that says that the "utility shall offer to wholesale customers, pro rata access to El Paso and Transwestern pipelines for their core load". Long Beach argues that wholesale customers should be free to nominate their core requirements over El Paso or

Transwestern without restrictions, and that SoCal should deliver these volumes as if it were SoCal nominating for its own core.

SoCal responds that the alternative approach that Long Beach proposes is not clear. SoCal argues that Long Beach's request is not based on any Commission order and that its tariff language is consistent with the language of D.90-12-100 at page 3.

Discussion
CACD compared the decision language under D.90-12-100 with the tariff schedule for Long Beach. The decision states:

> "We will also adopt Long Beach's proposal that its core load should share access to the El Paso and Transwestern pipelines on a pro rata basis with SoCal's core load."

SoCal's tariff states:

> "utility shall offer to wholesale customers, pro rata access to the El Paso and Transwestern pipelines for their core loads. " (Special Condition 11, GN-70).

The distinction is fine, but what SoCal's tariff provides is pro rata access to the pipelines for Long Beach's core loads, not shared access with SoCal for parity with SoCal's core loads. SoCal's total capacity is comprised of 30% on the Transwestern pipeline and 70% on the El Paso pipeline. To SoCal, its statement means that access will be provided to Long Beach's core loads on a pro rata basis with everyone else....30% of total capacity on the Transwestern system and 70% of total capacity on the El Paso system. The pipeline access provided to Long Beach is not necessarily on a pro rata basis with SoCal's core load. CACD recommends that SoCal rewrite this provision, so that it clearly states that Long Beach may have such access.

Core Requirements
Long Beach protests the interplay of the rules for SL-2 customers as it relates to full requirements customers. Long Beach also protests SoCal's application of balancing provisions of Rule 30 to core requirements.

Discussion
SoCal responds that Advice Letter 2009 was filed before the Commission issued D.91-02-022, which modified earlier decisions and moved wholesale core loads from SL-2 to SL-1. SoCal states that its final tariffs will reflect this change in the service levels to wholesale customers and that these issues are now moot.

Storage
Long Beach protests the omission of any storage designation for its core service requirements. SoCal agrees that the Commission

did not change this authorized service for Long Beach and that the proposed tariff sheets need to be changed to reflect this right.

Discussion

CACD recommends that the storage provisions for Long Beach be reinstated to allow storage for its core service requirements. SoCal should refile this change in its supplemental advice letter.

ACCOUNTING

Core Rate Trigger Mechanism

TURN and DRA note that SoCal and SDG&E did not change the description of the core rate trigger mechanism or determinates in the Preliminary Statement, nor did they update the language to reflect the appropriate conditions under which the utility may file for a change in core rates during the BCAP period. Long Beach also noted that SoCal needed to reference its most recent ACAP decision.

SDG&E agrees that its description of the core trigger mechanism needs to be changed and will do so in its supplemental filing. SoCal agrees that the core trigger rate change filing date needs to be updated to reflect the BCAP dates. However, SoCal requests that it not have to change this immediately, because it and other issues are the subject of a pending Petition to Modify.

Discussion

SoCal did not respond to the issue of using the old formula to calculate the trigger filing. CACD compared the Preliminary Statement language used with Decision 90-12-100 and found that SoCal had not changed this section. Both SDG&E and SoCal should revise their Preliminary Statement language describing the core trigger mechanism to reflect D.90-12-100, Appendix A, Page 3, and both should update the references to the most current ACAP decisions.

Core Take-or-Pay Account

TURN objects to the February 1 date proposed by PG&E in its Preliminary Statement (Part AA, Sheet 13566-G), to "zero-out" the Core Take-or-Pay Account. TURN suggests that since this account was created as a result of PG&E's ACAP D.90-04-021, any zeroing-out should occur on the anniversary of the account's creation. Therefore, TURN recommends that PG&E change the proposed date from February 1 to April 1.

PG&E responds that the February 1 date was determined in D.90-04-021, and is not affected by the Procurement OIR. However, PG&E will not oppose TURN's proposal to zero-out on April 1st instead, providing that the February 1 through March 31 account activity would be trued-up in the next cost allocation proceeding.

Discussion

CACD investigated the core take-or-pay account authorized in D.90-04-021 and found that this account handles core-related, El Paso take-or-pay charges. The decision adopted a one-way balancing account for the estimated, core-allocated amounts which were subject to refund.

CACD contacted PG&E regarding the disposition of this account. PG&E stated that it zeroed-out the account balance on March 31, and will request a true-up of the balance in the next cost allocation proceeding.

Noncore Rate Trigger Mechanism

TURN, DRA and CIG protested the provision of a noncore rate trigger mechanism proposed in both PG&E's and SDG&E's advice letter filings. The protesters state that inclusion of the noncore trigger is noncompliant with D.90-09-089 and D.90-12-100. Neither decision authorized a noncore rate change during the BCAP period.

CIG argues, however, that if the Commission adopts the noncore trigger mechanism for the utilities, opt-out provisions must be included to protect noncore customers. CIG states that PG&E has failed to provide the corresponding Settlement language that would allow noncore customers to opt-out of their Service Level 2 contracts, if the noncore rate trigger results in noncore transmission rates increased by a percentage greater than 150% of the Consumer Price Index.

PG&E responds that the proposed trigger system would be occasioned by a large forecasting error once cost allocation proceedings become biennial rather than annual. PG&E argues that no valid regulatory objective is served by rewarding or penalizing ratepayers and shareholders with large windfalls or costs due to forecasting errors. Allowing a balancing account to grow substantially beyond a certain level can result in rate instability. The intent of the Noncore Rate Trigger is to provide less variation between forecasts and actual occurrences, thereby promoting rate stability.

SDG&E agrees with the protesters that the procurement decisions did not provide authorization for a noncore trigger mechanism. However, D.90-09-089 granted SDG&E authority to procure gas for its noncore, non-UEG customers. SDG&E states that its noncore, non-UEG customers receiving transportation service at levels 2 through 5 must commit to the same obligations as core subscription customers, if they purchase utility gas. SDG&E argues that since these noncore customers have the same obligations as core subscription customers, they should also have the same opportunity for rate stability. The purpose of allowing core adjustments to correct balancing account over- and undercollections is rate stability. SDG&E believes that a similar provision is necessary to protect its noncore customers.

In a subsequent conversation with SDG&E, CACD learned that SDG&E distinguished its proposal from PG&E, stating that it is requesting the mechanism to operate on the balancing account only, while PG&E is also incorporating an updated throughput forecast.

Discussion

The stated purpose of the utilities' proposed noncore trigger mechanism is to provide stability for the transportation rates of noncore customers. Under the gas restructuring implementation decision, D.87-12-039, the Commission adopted a non-interest bearing, memorandum account for noncore fixed costs, which tracks transportation revenues with forecasted throughput and revenues. The company and shareholders are at risk for the resulting over- or undercollection of this account. The trigger mechanism would serve to readjust the transportation rate between cost allocation proceedings, should an extreme change occur.

The Commission did not adopt the Settlement's noncore trigger mechanism in any of the procurement decisions. Due to the changes necessitated by the procurement decisions, the Commission did adopt a 75% balancing account treatment for noncore transportation revenues, ameliorating the utility risk for recovery of these revenues with the forecasts.

Under the procurement decisions, no changes have occurred which will jeopardize the utilities' cost recovery of noncore transmission revenues, nor have the utilities offered arguments supporting the need for noncore transportation rate "stability". However, extreme future circumstances could warrant the need for an adjustment of noncore transportation rates between cost allocation proceedings. CACD recommends that should such circumstances occur, the utilities petition the Commission to make an adjustment. CACD recommends that the PG&E and SDG&E remove the noncore trigger mechanisms from their Preliminary Statements to comply with the procurement decisions.

Noncore Purchased Gas Account

TURN protests that there is no Commission authority allowing PG&E to transfer the August 1 balance in the current Noncore Purchased Gas Account (NPGA) into the Core-Subscription Subaccount of the new consolidated PGA. TURN states that the existing NPGA account is a memorandum account, not a balancing account. TURN argues that PG&E has no basis upon which to presume that any remaining balance should be recoverable from ratepayers, particularly a different group of ratepayers (core subscription) from those who caused that balance to accrue (purchasers from the noncore portfolio).

PG&E argues for retention of this transfer. PG&E states that the NPGA balance for the past three years has remained very small, fluctuating around zero, with only short-term estimation errors. PG&E believes that no purpose would be served to credit or debit ratepayers or shareholders by such a small amount. PG&E argues that this small balance is due to the current practice of adjusting the noncore WACOG each month for estimation errors, eliminating risk to both ratepayers and shareholders.

Discussion

TURN argues that PG&E cannot presume that any remaining noncore portfolio balance should be recoverable from a new set of core subscription ratepayers, particularly when old, noncore portfolio customers caused that balance to accrue. PG&E does not see that core subscription customers would be harmed, for it states that the noncore PGA balance is very low.

Without knowledge of what this balance will be on July 31, CACD recommends that PG&E not be authorized to transfer any of the noncore portfolio balance to the core subscription PGA balance. CACD recommends instead that the PG&E and SoCal balances be set aside as of July 31, 1991 for disposition in each utility's next cost allocation proceeding.

SURCHARGE CREDIT

Distribution

APMC and DRA argued that PG&E proposed to credit the firm surcharges to Service Levels 3 through 5, not to all noncore customers, including Service Level 2 customers, as authorized in D.90-12-100.

PG&E replied that it has filed a petition to modify D.90-12-100 regarding the firm surcharge, and that it will comply with any subsequent Commission decisions on this issue.

Discussion

Commission Decision 89-09-089 adopted a surcharge of 1.2¢/therm for firm Service (Service Level 2). It also directed the utilities to credit the revenues collected from this surcharge to the interruptible services (Service Levels 3 thru 5). Decision 90-09-089 was modified by D.90-12-100, which ordered the utilities to apply the surcharge to Service Levels 2 through 5. Decision 91-02-046 reconsidered the distribution of the surcharge and reinstated its application to Service Levels 3 through 5. This issue is moot.

Surcharge Credit

APMC/CPG objects to the way PG&E has calculated interruptible rates for its noncore customers. APMC/CPG believes that PG&E's calculation does not comply with D.90-09-089 and D.91-02-046 and that it does not result in an "equal cents per therm" credit for Service Levels 3 thru 5.

APMC/CPG argue that overall, PG&E's Electric Department and electric ratepayers will receive a lower interruptible credit, on a cents per therm basis, from other noncore customers. APMC/CPG also claim that parity between cogenerators and the UEG will not be achieved because PG&E's UEG would pay a higher rate than cogenerators for its interruptible volumes. APMC/CPG proposes removal of both the firm service surcharge and the interruptible credit from the UEG demand charge, and recommends application of these charges/credits to UEG usage on a volumetric basis, as it is applied to other noncore customers. APMC/CPG also proposes to base the calculation of the credit on expected hydro conditions and the latest forecast of UEG usage (PG&E's 1991 ECAC, UEG gas usage forecast) instead of using an average hydro year forecast of UEG volumes, as PG&E has proposed.

APMC/CPG has calculated the interruptible credit to be $0.0918 per decatherm instead of $0.1374 per decatherm. APMC/CPG notes that since the surcharge/interruptible credit is intended to be a transition mechanism until the capacity brokering is implemented, its proposed mechanism will minimize any balance in the surcharge/interruptible credit balancing account once this mechanism expires.

PG&E responds that it has applied the firm surcharge and interruptible credit on an equal cents per therm basis correctly to its UEG forecasted service and believes that Advice Letter 1624-G-A is in compliance with D.90-09-089 and D.91-02-046 and the Settlement. PG&E notes that APMC/CPG's proposal, although sensible for the UEG rates for firm service, will result in a negative UEG interruptible service Tier II rates.

PG&E further opposes APMC/CPG proposal to use the forecast of UEG throughput from PG&E's ECAC application A.91-04-003. PG&E argues that there is no provision in any of the CPUC decisions that allows for the use of a UEG throughput other than that adopted for gas rate design purposes in the ACAP. PG&E further argues that the CPUC has determined that cogeneration parity is achieved when the cogeneration rate is set equal to the forecasted UEG rate. PG&E states that if cogenerators pay the forecasted interruptible rate paid by the UEG, parity is achieved regardless of whether the actual average interruptible rate paid by the UEG differs from the forecasted rate.

Discussion

The Settlement proposed a 1.2¢/therm surcharge for Service Level 2 customers with revenues from this surcharge to be credited to customers in Service Levels 3 through 5. Further, the Settlement proposed to eliminate demand charges for all industrial customers except UEGs. D.90-09-089 adopted both the 1.2¢/therm surcharge to be redistributed among Service Levels 3 through 5 customers and the provision for eliminating demand charges for all noncore customers except UEGs. Later, D.90-12-100 concluded that UEG customers are not distinguished from other noncore customers in terms of paying demand charges for transportation, and therefore, demand charges were eliminated for UEG customers.

PG&E has calculated the UEG's interruptible credit based on the Settlement mechanism which proposed to apply the UEG's firm surcharge and interruptible credit to UEG's demand charges.

Since D.90-12-100 eliminated demand charges for UEGs, PG&E's calculation of interruptible credit to its UEG customer is inaccurate and should be revised. PG&E should apply the appropriate charges and credits to its UEG customer based on a volumetric usage, the same way these charges are applied to PG&E's other noncore customers for an equal cents per therm distribution.

In addition, the forecast of UEG gas use should be based on the most recent gas proceeding forecast available. CACD recommends using PG&E's 1991 ACAP, adopted on May 8, 1991, in determining UEG volumes.

<u>Monthly True-Up</u>
TURN, DRA, SCE, and CIG protest SoCal's proposal to perform a monthly true-up of the firm transportation surcharge credit. CIG and DRA oppose SDG&E's retention of the surcharge revenues until the next BCAP proceeding. TURN states that based on the statements in D.90-12-100 regarding the "virtues of rate predictability", SoCal's plan to change noncore transportation rates monthly would be disruptive, when it was the Commission's intent to enter into more stable, longer-term gas supply arrangements. DRA echoes TURN's protest and adds that to do so will aggravate the implementation of the discount adjustment mechanism. (This scenario was likely under the previous decision where the credit was distributed to SL-2 noncore customers as well as SL-3 through SL-5 customers).

DRA recommends that the utilities forecast the SL-2 surcharge revenues and apply this to the noncore rates. In addition, DRA recommends that SDG&E's Noncore Premium Surcharge Account (NPSA) accrue interest because of the time lag between the collection of revenues and the credit back to noncore customers. CIG concurs, stating that it supports the tracking account adopted in D.90-12-100 and the procedure for annual crediting of surcharge revenues on a forecasted basis which was adopted by PG&E.

SoCal replies that D.90-12-100 authorized a balancing account for the crediting of this revenue, but that the adopted rules refer to the time period for application of the account as "in subsequent periods." SoCal has elected to adjust the credits monthly rather than the annual adjustment proposed by PG&E.

SoCal submits that a monthly adjustment is preferable, because it will prevent the accrual of large under- or overcollections. SoCal states that the potential for large accruals is great because of the inherent uncertainty in predicting the annual level of SL-2 subscriptions that will occur. SoCal argues that its monthly adjustment is justified for it will provide customers with more accurate, real-time information about the premium value that the market places on firm transmission service.

SDG&E argues that the Commission stated in D.90-12-100 (page 4) that "it is unreasonable to expect an accurate forecast of SL-2 customers before having had any experience with our new priority system." SDG&E also notes that there is no authorization for such a mechanism in D.90-09-089, D.90-12-100, or D.91-02-022. SDG&E believes that CIG and DRA's proposal increases uncertainty, since it puts the customer and the company at risk for forecasting inaccuracies. SDG&E corrects DRA, stating that its proposed tariff does not reflect returning surcharge revenues on a monthly basis. However, SDG&E agrees with DRA that the account should accrue interest.

Discussion

Decision 90-09-089 adopted the Settlement's pricing provisions, which were:

1) charges for Service Levels 3-5 would be at the default rates, subject to negotiation;

2) the revenues from the 1.2¢/therm surcharge would be credited on a forecast basis against the default rates applicable to customers in Service Levels 3-5; and,

3) a tracking account would be established to protect the utilities from forecast errors.

As noted above, Decision 90-12-100 changed the distribution of the surcharge revenues to Service Levels 2-5, while D.91-02-046 returned this distribution to Service Levels 3-5. In addition, Decision 91-02-046 states:

> "We will direct the utilities to provide estimates to their transportation customers of rebates they may receive at the end of the ratemaking period, based on demand for various transportation services. Alternatively, as PG&E suggests, they may credit interruptible rates immediately based on forecasted demand, subject to adjustment at the end of the ratemaking period."

The issue to be settled here is when surcharge revenues are to be credited to noncore customers. Contrary to SoCal's response, Decision 90-12-100 adopted a tracking account, not a balancing account for the collection of the 1.2¢/therm surcharge. Neither SoCal nor SDG&E prefer to forecast these revenues. SDG&E would credit them at the end of a ratemaking cycle adding interest to the balance, while SoCal would true-up the accumulations on a monthly basis. PG&E prefers to forecast the revenues, credit customers on a regular basis, and adjust the final amounts at the end of the ratemaking period.

CACD recommends that all three utilities distribute these forecasted or actual funds consistently, preferably on a monthly basis.

Customers with Negotiated Rates
CIG protests SoCal's interruptible transportation Schedules GT-33, 34 and 35 which state that customers paying negotiated rates are not eligible for the firm transportation surcharge credit. CIG argues that this provision is at odds with D.90-09-089 and the underlying Settlement, and is discriminatory to those customers with negotiated rates.

SoCal replies that its reason for this provision was to provide equal treatment for all customers. SoCal's concern is with those EOR customers having substantial discounts under existing long term contracts. SoCal objects to crediting the surcharge revenues to customers with existing contracts at rates below default rates, but does not object to crediting customers with existing contracts at default rates or new contracts where the credits can be anticipated in the drafting of those contracts.

Discussion
Decision 90-09-089, cited above, adopts the Settlement's distribution of the surcharge credit to Service Level 3-5 customers paying the default rate. None of the subsequent procurement decisions modify this. SoCal should adhere to its provisions, crediting the surcharge to those customers with and without negotiated contracts paying the default transportation rates. However, in the interest of fairness, noncore customers with negotiated transportation contracts should be credited with the surcharge credit, only in an instance where the negotiated rate differential is less than the difference between the default rate and the surcharge credit.

RATE COMPONENTS

LUAF/GDU Gas Costs
DRA objects to Part C.10.b of PG&E's Preliminary Statement which includes Lost and Unaccounted for (LUAF) gas and Gas Department uses (GDU, or in-kind shrinkage gas) as part of the total procurement costs. DRA notes that there is no authorization for the transfer of costs associated with LUAF and GDU from the transportation rate to the procurement rate. DRA argues that this proposed transfer would result in the utility being no longer at risk for LUAF and GDU revenues since procurement costs receive 100% balancing account treatment.

Similarly, DRA objects to SDG&E's noncore procurement Schedule GPNC, Special Condition 8, which includes company use and lost unaccounted for gas costs in brokerage fees. DRA argues that there is no authorization for shrinkage costs in the brokerage fees.

CIG objects to PG&E's Schedules G-CIG, G-FT, G-IT and Rule 21 regarding the in-kind shrinkage charges. CIG argues that the transportation rates for all noncore customers currently include a component for compensation of shrinkage and is concerned that PG&E will be double recovering the shrinkage cost. CIG recommends that an appropriate reduction in noncore transmission be made in order to preclude double recovery. In addition, CIG argues that the reduction must be made before the in-kind shrinkage provision is allowed to go into effect.

SDG&E agrees with DRA and will file revised tariffs deleting this language from Special Condition 8 of Schedule GPNC.

Conversely, PG&E argues for retention of its proposal. PG&E has filed tariffs that require transportation customers to supply their own LUAF and GDU. PG&E believes that under this provision, it will only need to provide LUAF and GDU supplies for core and core-subscription procurement customers. PG&E argues that since these costs are actually procurement costs, they are more appropriately recovered through the procurement rates. PG&E also believes that this provision is consistent with Commission efforts to unbundle procurement and transportation rates and will benefit all customers.

PG&E adds that since May 1988, the cost for all customers' LUAF and GDU has been included in the transportation rate, because PG&E provided this supply for both procurement and transportation customers. PG&E explains that the shrinkage cost was removed from the transport rate in the shrinkage calculated in Advice Letter 1624-G and that this expense will be placed into the commodity rates in PG&E's future supplemental filings. Additions to the shrinkage expense will be reduced by the amount allocated to transport customers for the period beginning August 1, 1991. PG&E believes that these changes to the rate structure and the total allocated cost will ensure that PG&E does not double recover shrinkage costs during any period.

<u>Discussion</u>

Lost and unaccounted for gas and in-kind shrinkage gas are supplies and costs associated with the transportation of gas and are not a function of procurement. PG&E may have to supply gas to make up for the losses, but this action is caused from operating its system and is a cost of "doing business" for which the company is at risk. These supplies are not destined for the ultimate use of the customer. Accordingly, these costs should not receive the balancing account treatment appropriate to the Purchased Gas Account. CACD recommends that PG&E and SDG&E revise all of their proposed tariff changes to reflect that LUAF and GDU costs are associated with the transportation rate and not the procurement rate or brokerage fees.

<u>In-Kind Shrinkage Factor</u>

TURN sees virtue in an In-Kind Shrinkage Charge for transportation gas, but disagrees with PG&E's use of 2.7% for LUAF as proposed in tariff sheet 13621-G, Rule 21. TURN instead recommends the use of 3.1%, the forecasted shrinkage volumes adopted in D.90-04-021, or the equivalent number from this year's ACAP.

In response to TURN, PG&E states that the proposed 2.7% is based on an 11-year simple average of actual shrinkage volumes. PG&E, however, does not oppose TURN's proposal to use the in-kind shrinkage percentage adopted in the most recent Cost Allocation Proceeding.

Discussion
In conjunction with the LUAF and GDU discussion above, PG&E should update its shrinkage factor to reflect the most recently adopted ACAP rate, if this has not been done under its supplemental filing. CACD recommends that when PG&E refiles its tariffs removing in-kind shrinkage charges from its commodity rates and returning them to the transport rates, as well as updating the rate to reflect the adopted shrinkage factor from its most recent ACAP, that it also provide a detailed worksheet outlining the rate changes made.

Brokerage Fees
CIG protests that the SDG&E's Schedule GCORE does not provide for brokerage fees. CIG also objects to SDG&E's provision of a ceiling on brokerage fees of $10,000 per month for any single customer and requests its elimination.

SDG&E states that its brokerage fees are embedded in GCORE rates rather than itemized. Also, SDG&E notes that the provision of a brokerage fee ceiling was contained in the original OIR Settlement.

Discussion
Decision 90-12-100 (page 3, Appendix) provides that the brokerage fee for core subscription procurement shall be in the amount adopted in the utility's cost allocation or other appropriate proceeding. None of the procurement decisions adopted the brokerage fee ceiling outlined by the Settlement.

Decision 89-03-014 directed PG&E and SoCal to establish a brokerage fee to provide a more efficient price signal to procurement and transportation customers. This decision did not order SDG&E to establish a brokerage fee. CACD notes that in addition to the brokerage fee cap, SDG&E inserted a 0.14¢/therm brokerage fee in its rate schedules. When CACD asked about the basis for this charge, SDG&E responded that it developed the value as a proxy by taking 10% of its noncore transmission rate.

Since SDG&E provides bundled and unbundled services for its customers, it is reasonable to provide its customers, especially its transport-only customers, with a price signal identifying these costs. However, the use of the proxy inserted by SDG&E is not authorized. In addition, the basis of such a fee should be on procurement-related costs, not transmission-related costs. SDG&E should develop a study to identify its brokerage costs to present in its next ACAP. Meanwhile, SDG&E should eliminate the unauthorized, brokerage fee cap in its procurement filing, as well as the proxy brokerage fee. CACD recommends that SDG&E add a provision stating that its current brokerage costs are embedded in the gas portfolio WACOG.

PENALTIES

Take-or-Pay Penalty & Procurement Charges

DRA states that the take-or-pay penalty rate and the procurement charges in SoCal's core subscription schedules are specified incorrectly. DRA states that the penalty should be modified to incorporate the provision that the take-or-pay will be 14% of the current WACOG of the utility gas supply portfolio until a decision is issued setting forth a cost-based charge. In addition, DRA states that the procurement charge should be set equal to the actual recorded WACOG, lagged one month, as required by D.90-12-100.

SoCal replies that the take-or-pay penalty rate of 14% in the core subscription schedules is stated correctly and questions the necessity of also stating that this value will change in the future. With respect to the procurement charge calculation, SoCal states that the WACOG posting is made several days before the beginning of the effective month, before the actual gas costs are known, and that the posted price includes actual and estimated costs. SoCal intends to continue this practice, because the alternative is to wait for two months until all the data is available to post the WACOG price. According to SoCal, this alternative distorts the "current" price of gas, giving the wrong price signals to customers.

Discussion

Customers not only should be made aware of the consequences of their actions, but they should be alerted to which rate elements change, how often, and why. All of these factors need to be present in the tariffs in order to promote a clear understanding of them and how they operate. This is especially important under the present circumstances where a number of elements are changing at once. SoCal offers no sound reason to omit alerting customers to the fact that the 14% take-or-penalty will vary with the core WACOG or that this percentage is a proxy, subject to a pending proceeding which will adopt a methodology to determine a cost-based charge.

With respect to the issue of the WACOG calculation, DRA and SoCal have an argument with semantics, not with each other. To comply with the Commission's monthly requirements, SoCal's adopted methodology must rely on a combination of actual and estimated data to develop a reasonable approximation of the monthly WACOG. This is because some transactions require adjustments beyond a one month lag, due to interstate adjustments. CACD has no objection to SoCal's current methodology.

Standby Charges & Brokerage Fees
DRA protests that SoCal's schedules for noncore, transportation-only services contain standby provisions which include brokerage fees in the rates and that this is not authorized. DRA cites that SoCal's inclusion of the brokerage fee does not comply with page 8 of Appendix A of D.90-12-100, which sets the standby rate equal to 150% of the core WACOG for the month, or the highest incremental gas cost for the month. DRA claims that there is no authorization for charging a procurement "brokerage fee" for standby procurement service in addition to the gas cost formula (highest incremental cost or 150% of WACOG) adopted in D.90-09-089.

SoCal disagrees with DRA, stating that previous Commission orders required gas utilities to charge a brokerage fee for all procurement service provided to noncore customers. SoCal says that there is no indication in D.90-09-089 that the Commission intended to revise its previous orders on this subject.

Discussion
CACD researched the various OIR procurement decisions and verifies that, although D.90-09-089 refers to the various proposals of the settlement parties which included a standby procurement penalty and a brokerage fee, the decision only adopts the OIR's higher (by 30%), proposed, 150% penalty and is silent on the brokerage fee issue. The per therm increase of the brokerage fee above the 150% penalty is roughly 0.6%.

Two of the Commission's objectives in D.90-09-089 were to set price levels to protect core customers from increased liabilities and to encourage noncore customers to plan their transportation and gas purchases carefully. The Commission wanted to create sufficient penalties to deter system abuses. The 150% amount represents the replacement of the commodity and a sufficient penalty to a customer which uses gas destined for someone else. While a 150% penalty is steep, it was not identified as compensation to the utility for the procurement of the gas. SoCal should be allowed to recover its brokerage fee in addition to the penalty. PG&E should be allowed to recover this amount as well, but SDG&E should not. Until a brokerage fee is adopted, SDG&E should not be allowed to recover a brokerage fee in addition to the penalty.

Use-Or-Pay Liabilities
Long Beach charges that SoCal's tariffs are ambiguous regarding the potential exposure of SL-2 full requirements customers to a use-or-pay liability. It recommends that SoCal adopt PG&E's language, which states explicity that such customers have no exposure, except to the extent that they burn alternative fuel.

SoCal believes that its tariffs are clear regarding SL-2 full requirement customer liabilities regarding use-or-pay penalties. However, SoCal states that is does not object to replacing its language with that used by PG&E.

Discussion
Under the core subscription, full requirements option, PG&E states that:

> "Any unauthorized alternative fuel use will be penalized by a cents-per-therm basis for all displaced natural gas use, as determined by PG&E, at 80 percent of the applicable Transportation Charge under this schedule for the period in which the Customer used unauthorized alternative fuels."

By comparison the SoCal use-or-pay statement for core subscription, full requirements customers does not flag the customer with the word "penalty". Instead, SoCal uses the phrase 'the customer will be subject to a charge'. The indefinite wording indicates that SoCal may or may not charge the customer, rather than clearly announcing that a penalty will be assessed. CACD recommends that SoCal insert language that is similar to that used by PG&E.

BILLING

Meter Reads
CIG requests that PG&E modify its firm and interruptible transportation schedules G-FT and G-IT, to provide that PG&E will read meters so that the billing months of customers on those schedules coincide with calendar months. CIG believes that this match-up will help avoid confusion.

PG&E responds that it intends to read meters on a calendar month basis whenever possible for all transport customers. PG&E adds that due to manpower constraints, reading meters on a calendar month basis requires meters which provide daily reads. PG&E states that such meters have not yet been installed for all transport customers, and therefore, the proposed tariff language should remain unchanged.

Discussion
CACD agrees confusion can be avoided if PG&E reads its meters so that the billing months of customers under the firm and interruptible schedules coincide with calendar months. However, CACD also agrees that to do this for all transporting customers at this time is problematic, given the unequal installations of standard and electronic meters for these customers and the personnel constraints; thus PG&E should retain its current meter tariff language.

Steam Meters
CIG notes that PG&E's cogeneration Schedule G-COG includes steam meters as among those required to determine the amount of gas service to cogeneration customers. CIG states that this issue is pending at the Commission and requests deletion of the requirement.

PG&E responds that the metering provision has been a part of PG&E's cogeneration tariff since 1981, when it was first adopted. PG&E states that this provision is approved by the Commission and until the Commission changes its position on this issue the tariffs should remain unchanged.

Discussion

CACD recommends that the current tariff for steam meters be retained by PG&E until the Commission changes the requirements.

Billing Adjustments

CIG argues that customers should not be required to pay standby charges or imbalance penalties based on estimated bills that may be erroneous. CIG notes that the utilities' rules indicate that buy-back and standby penalties assessed in error will be refunded. CIG recommends that the utilities be prohibited from retroactively assessing any buy-back penalties or standby charges based upon a subsequent readjustment of the customer's bill.

PG&E agrees with CIG on the issue of imbalance penalty credits and standby charges billed in error and will modify its tariff to reflect these positions. SDG&E believes that if billing amounts are incorrect due to a defective meter, the error should be corrected subject to the appropriate statute of limitations. SDG&E argues that there is no reason to allow a defective meter to result in a windfall either to the customer or to the utility. SDG&E comments that CIG's proposal would conflict with SDG&E's existing Rule 18 (Meter Tests and Adjustment of Bills) which provides for backbilling in the event of defective meters.

SoCal disagrees with CIG's recommendation. It argues that the imbalance rules are not based on a make-up period that runs from notice to the customer. SoCal states that under the rules for imbalances, the customer is responsible for being within imbalance tolerances at the end of each month. SoCal argues that there is no reason to relieve a customer of imbalance penalties merely because the complete information was not made available by the transporting interstate pipeline until after the close of the billing period. SoCal argues that the harm is the same regardless of when the knowledge of the imbalance is received, and the customer has no right to make up the imbalance in any case.

Discussion

CACD supports the utilities' arguments in this instance. If the utility makes a billing error which overbills the customer, the utility must refund the difference. If the utility underbills the customer, the customer is liable for the difference bill and any associated penalty. These principles are sound, even under the circumstances where subsequent billing adjustments are made as a consequence of interstate pipeline corrections.

The pipelines and the utilities have or will have electronic bulletin boards and customer-specific information available to transporters so that they may foresee and correct for their own imbalances. Customers may also read their own meters and/or install electronic metering to insure against imbalances. These protections should provide the customer with some advance warning that a billing may be erroneous so that corrective action can be taken. CACD recommends that a customer should not be relieved of imbalance penalties when a subsequent billing adjustment is made.

MISCELLANEOUS

Use-or-Pay Charges

CIG objects to SoCal's GT-30 Schedule under the "Minimum Charge" section which states that the minimum monthly charge shall consist of the monthly customer charge plus any applicable use-or-pay charges. CIG argues that the reference to use-or-pay charges as a component of any minimum monthly charge is inconsistent with the provisions of D.90-09-089 and that use-or-pay charges for SL-2 and SL-3 customers are measured on an annual basis, not monthly.

SoCal agrees with CIG that the use-or-pay obligations for SL-2 and SL-3 are to be calculated on an annual basis, and that a tariff modification is appropriate.

Discussion

The procurement decisions provided that the use-or-pay obligations for SL-2 and SL-3 are to be calculated on an annual basis. CACD recommends that SoCal make this revision in its supplemental procurement filing.

Base Cost Amount Factor

DRA argues that SDG&E's Preliminary Statement (page 10) states incorrect factors to allocate its base cost amount. The factors should be updated to comply with D.90-11-023.

SDG&E agrees that it used erroneous factors and will file revised tariffs to correct this error.

Discussion

CACD verified that the cost allocation factors used by SDG&E had not been changed under its ACAP filing to comply with D.90-11-023, Appendices I & J. CACD recommends that SDG&E update its cost allocation factors to comply with this decision when it refiles tariff corrections to its procurement filing.

Carrying Cost of Gas In Storage

DRA states that SoCal's Preliminary Statement (Sheet 19 of 33: Part E.3.i) incorrectly included the Carrying Cost of Gas in Storage in the balance on which interest is assessed. PG&E's 1989 ACAP, D.90-04-021 was silent on the issue of interest on

Carrying Cost of Gas in Storage true-up. Accordingly, PG&E did not calculate the interest on the Carrying Cost true-up. In the interest of consistency, DRA believes SoCal should adopt the precedent set in D.90-04-021 and should change this section to read:

> "An entry equal to interest on the average of the balance in the account during the month less the difference between the Commission's authorized and recorded Costs for Carrying Costs of Gas in Storage, calculated in the manner described in Preliminary Statement, Part F."

SoCal responds that a number of DRA's recommended changes to SoCal's Preliminary Statement have merit and that they will take these suggestions under advisement. SoCal did not specifically respond to this recommendation.

Discussion

In the interest of consistency with treatment of interest for the Carrying Cost of Gas in Storage, CACD recommends that SoCal file a modified Preliminary Statement, adopting the language recommended by DRA above.

Cogeneration Shortfall Account

TURN filed a protest to Advice Letter 1624-G on February 7, 1991. TURN protested the references to the Cogeneration Shortfall Account (CSA) in PG&E's proposed tariffs. TURN states that the CSA was eliminated by D.90-04-021 (page 80) and requests removal of such references except where they are needed to permit amortization of any approved CSA balance.

PG&E agrees to eliminate all unnecessary references to the CSA in its supplemental filings.

Discussion

Last year's ACAP decision, D. 90-04-021, ordered PG&E to discontinue entries to the CSA Account. PG&E should comply with that Decision and modify its tariffs eliminating the CSA account and all references to this account in the body of its Preliminary Statement.

Supplemental Advice Letter Filing

DRA recommends that Advice Letter 1624-G be rejected. DRA also recommends that PG&E not submit a complete set of tariffs for review and only submit the sheets that are revised with an index which cross references the pages in Advice Letter 1624-G with the new revised tariff sheets.

PG&E responds that it will file supplemental Advice Letter 1624-G-A to comport with changes resulting from recent Commission decisions and resolutions, and also to correct minor errors. PG&E states that the changes will be listed on a separate attachment. Any other changes due to the Cost Allocation Proceeding or related matters will be filed later.

Discussion

PG&E filed Advice Letter 1624-G-A on March 26, 1991. PG&E has not furnished any cross reference to ease review of this filing.

Natural Gas Vehicle Account

TURN states that PG&E's Natural Gas Vehicle (NGV) Account, in the Preliminary Statement, should include provision for accrual of interest on the account balance.

PG&E responds that the NGV Account was established in D. 90-04-021 (PG&E's 1990 ACAP) and became effective as of April 19, 1990. PG&E explains that this account has been a memorandum account, which does not accrue interest. PG&E feels that the nature of this account is not affected by the OIR proceeding, and suggests that such issues be raised in the Cost Allocation Proceeding.

Discussion

Memorandum accounts do not usually accrue interest, unless specifically ordered by the Commission. CACD agrees with PG&E and suggests that TURN present its proposal that the NGV account accrue interest in PG&E's next cost allocation proceeding. PG&E should not add interest to its Natural Gas Vehicle Account at this time.

Workpapers

CCC states that it informally asked PG&E to provide workpapers supporting its filing and that this request was denied by PG&E.

PG&E responds that the workshop to the OIR held among the parties in December did not specify filing of workpapers. PG&E states that it will file additional filings to comply with the Commission's future resolutions and decisions regarding this issue, as well as any rate changes due to ACAP filing. PG&E recommends that CCC file a written request for workpapers, if the future OIR filings do not address CCC's concerns.

FINDINGS OF FACT

1. SoCal is not authorized to state that it will transfer its firm capacity rights to its customers.

2. SoCal's customers may make special agreements with the Utility to transport on a best efforts basis the customer-arranged gas and to sell the gas to the customer.

3. PG&E's Customer Identified Gas Program requires its customers to reveal the price paid to a broker to an outside accounting firm.

4. Commodity prices paid should be confidential.

5. PG&E's open season is from April 1 through July 31, 1991.

6. SoCal has extended its open season from May 15 through June 10, 1991.

7. SDG&E has extended its open season from May 31 through June 21, 1991.

8. PG&E needs supply basin specification from its noncore customers on an annual and monthly basis to assure reliable delivery of supplies and to provide information to other noncore customers about supply basin availability for as-available demands.

9. A "buy-up" option from Service Level 3 to Service Level 2 when capacity is available during the summer months (April through October), will allow customers procurement flexibility and will optimize capacity use.

10. PG&E needs to gain information about a customer's ACQ and MDQ by supply basin to adequately assist some customers to match available supplies and locations and thereby optimize capacity.

11. PG&E's stated capacity for firm transportation customers will be made available to interruptible customers on a non-discriminatory, as-available basis.

12. PG&E's tariffs (Schedules G-FT and G-CIG) do not allow equal flexibility to firm transportation customers and firm core subscription service customers who opt for utility procurement.

13. SoCal does not include a definition of Maximum Daily Quantities and Annual and Monthly Contract Quantities in its tariffs and its Rule 1.

14. A customer should be allowed to renegotiate an MDQ if its position has changed significantly.

15. The adopted service level rules supplant the existing supply and capacity curtailment scheme.

16. A curtailment is a condition where either a supply or a capacity constraint interferes with normal deliveries of gas.

17. The distinction between a supply and a capacity curtailment is not known immediately.

18. A curtailment on the interstate pipeline system should not cause a curtailment to customer-owned, California-produced gas.

19. SoCal and SDG&E curtailment rules do not address diversions of customer-owned gas under Rules 14 and 23 respectively.

20. SoCal's tariffs do not include a curtailment protocol for Balancing, Storage, and Interutility Services.

21. The Commission's definition of Service Level 3 lacks the curtailment mechanism adopted for UEG and cogeneration volumes under Service Levels 4 and 5 to insure cogeneration parity.

22. Alternative fuel-capable, P2B - P5 customers should not be required to continue to maintain their standby facilities or fuel.

23. Customers classified as P2A, qualifying under the annual economic feasibility test, should be able to continue to establish this qualification on an annual basis.

24. Customers classified as P2A, with pending applications to be re-classified as noncore, should be able to qualify under the economic feasibility test until August 1, 1991.

25. Applications of P2A customers desiring to be reclassified as noncore after August 1, 1991 should be denied until this issue is addressed under OII 86-06-005.

26. Core P2A customers wanting noncore status should be identified on a list containing their historical volumes for cost allocation purposes.

27. Requiring customers to install an electronic meter at their own cost in order to participate in the program will alleviate the utilities' concerns about monitoring problems.

28. PG&E's phrase "unintentional and minor" in reference to imbalances is unnecessary.

29. PG&E's imbalance tariff does not allow a customer to trade any volumes within the 10% tolerance band.

30. The utilities must be able to approve all trades under the imbalance trading programs.

31. PG&E and SoCal are establishing electronic bulletin board programs to facilitate customer trades.

32. SDG&E's tariff incorrectly states in its Imbalance Trading Schedule that no related costs shall be recovered from the participants.

33. Allowing customers at least 20 days from the notice of any imbalance to make an imbalance trade provides sufficient time for the customer to arrange a trade.

34. SDG&E has established an imbalance trading form to facilitate imbalance trades among its customers.

35. SoCal does not specify that imbalances occurring in the same time period are eligible for trading.

36. SoCal does not define what the time period is for trading imbalances.

37. PG&E and SoCal did not submit advice letters outlining the program and bidding rules for sales of excess core gas to comply with the procurement decisions.

38. PG&E describes excess sales gas to SoCal and SDG&E under its interutility tariff to accommodate daily balancing operations, but PG&E should distinguish this service from its program to provide sales of excess gas to all bidders.

39. SDG&E has described the condition of excess gas supplies in its tariffs.

40. Core subscription service requires customers to commit to a two-year obligation. This requirement of D.90-12-100 should not be modified at this time.

41. Extending the full requirements option to Service Level 3 customers will allow program flexibility to annual, interruptible transporters.

42. PG&E's schedule for service to long-term contract customers does not provide that the Service Level 2 rate shall be one-half the difference between the current total rate and the SL-2 total rate plus 1.2¢/therm.

43. Applying the 65% nomination restrictions on UEG and EOR customers under Service Levels 2 and 3 on a seasonal basis should ensure capacity optimization.

44. SDG&E has proposed to have one procurement portfolio with three subaccounts.

45. SDG&E's core subscription tariff erroneously allows service under a one-year obligation.

46. SDG&E's core subscription tariff applies a wrong calculation for the use-or-pay penalty.

47. SDG&E's noncore procurement schedule (GPNC) retains an unauthorized special condition subjecting the customer to a 12 month payment of procurement costs.

48. Cogenerators will be provided notice of the UEG elections.

49. Cogenerators will have five business days from the close of the open seasons to finalize their elections.

50. Specification in the tariffs of the type of the cogeneration notice to be issued is unnecessary.

51. Cogeneration customers require information sufficient to understand the methods and calculations used to refashion the UEG schedules.

52. The Commission needs workpapers detailing the UEG rate design changes made to comply with D.90-12-100, in order to verify compliance with the currently adopted revenues, throughput, and cost allocations.

53. The Commission needs detailed worksheets of the changes to be implemented under the PG&E ACAP decision and the OII decisions as part of the supplemental filings made to comply with this resolution.

54. PG&E's Cogeneration Declaration complies with D.91-05-007 stating that the customer will be liable for 12 months backbilling for noncompliance.

55. PG&E's wholesale tariff does not provide core capacity access proportional to wholesale customers' core load outside the 450 MMcf limitation for noncore customers.

56. The utilities' schedules do not provide services for wholesale customers' noncore customers, either directly or through the wholesaler.

57. SoCal's tariffs do not allow Long Beach to have access to the El Paso and Transwestern pipelines on a pro rata basis with SoCal's core load as authorized.

58. SoCal's tariffs do not provide storage to Long Beach for its core service requirements as authorized.

59. SoCal and SDG&E did not revise their Preliminary Statement language relating to core trigger mechanism to reflect D.90-12-100, Appendix A, page 3, nor did they update the references to reflect the most current ACAP decisions.

60. PG&E and SDG&E inserted unauthorized noncore trigger mechanisms in their Preliminary Statements.

61. PG&E based its filing applying the surcharge credit and interruptible credit to the UEG demand charges, which were eliminated under D.90-12-100.

62. PG&E proposes to transfer the noncore portfolio balance to the core subscription PGA balance on August 1.

63. PG&E and SDG&E have filed unauthorized tariffs reflecting that LUAF and GDU costs are associated with the procurement rate or brokerage fees and not with the transportation rate.

64. PG&E has no authorization to remove in-kind shrinkage charges from transportation rates and place them into commodity charges.

65. SDG&E has added an unauthorized brokerage fee cap in its procurement filing, as well as a proxy brokerage fee.

66. SoCal does not clearly state that an SL-2, full requirements customers' use-or-pay liability is a penalty which will be applied if the customer burns alternative fuel with authorization.

67. The utilities' tariffs do not include refund provisions for buy-back and standby penalties assessed in error.

68. SoCal includes the carrying cost of gas in storage in the calculation of interest, which is inconsistent with adopted methodology.

CONCLUSIONS

1. The Commission should disapprove SoCal's tariff language stating that it will transfer its firm capacity rights to its customers.

2. SoCal's tariff language should provide that the customer may make a special agreement with the Utility to transport on a best efforts basis the customer arranged gas and to sell the gas to the customer.

3. PG&E should maintain its customers' price confidentiality by using an outside accounting firm to handle customer transactions.

4. PG&E should be allowed to require a customer to waive its commodity purchase price confidentiality rights only if the utility commences an action to recover unpaid bills.

5. The Commission should approve PG&E's open season from April 1 through July 31, 1991.

6. The Commission should approve the extension of SoCal's open season from May 15 through June 10, 1991.

7. The Commission should approve the extension of SDG&E's open season from May 31 through June 21, 1991.

8. PG&E should be allowed to require supply basin specification from its noncore customers on an annual and monthly basis to assure reliable delivery of supplies and to provide information to other noncore customers about supply basin availability for as-available demands.

9. The Commission should allow the utilities to provide customers a "buy-up" option from Service Level 3 to Service Level 2 when capacity is available during the summer months (April through October), to allow customers procurement flexibility and to optimize capacity use.

10. PG&E should be allowed to require an ACQ and MDQ by supply basin to adequately assist some customers to match available supplies and locations and thereby optimize capacity.

11. PG&E's stated capacity for firm transportation customers should be made available to interruptible customers on a non-discriminatory, as-available basis.

12. PG&E should modify its tariffs (Schedules G-FT and G-CIG) to allow equal flexibility to both firm transportation customers and firm core subscription service customers who opt for utility procurement.

13. SoCal should include a definition of Maximum Daily Quantities and Annual and Monthly Contract Quantities in its tariffs and its Rule 1, for a better understanding of the terminology and requirements.

14. The Commission should allow the utilities to renegotiate an MDQ if the customer's position has changed significantly.

15. SDG&E should adopt a consistent curtailment scheme with SoCal and PG&E, using the adopted service level rules.

16. The Commission should adopt the definition of a curtailment as a condition where either a supply or a capacity constraint interferes with normal deliveries of gas.

17. The Commission should delete the requirement that utilities distinguish between a supply and a capacity curtailment.

18. The Commission should require the utilities to provide that a curtailment on the interstate pipeline system should not cause a curtailment to customer-owned, California-produced gas.

19. SDG&E should add language to its tariffs addressing diversions of customer-owned gas under Rule 14, as outlined under the discussion.

20. SoCal should add language to its tariffs addressing diversions of customer-owned gas under Rule 23, as outlined under the discussion.

21. SoCal should add Balancing, Storage, and Interutility Services in its Rule 23 to clarify when and under what conditions these services will be curtailed.

22. The Commission should require the utilities to apply the curtailment mechanism adopted for UEG and cogeneration volumes under Service Levels 4 and 5, to Service Level 3 volumes to insure cogeneration parity.

23. The Commission should adopt that alternative fuel-capable, P2B - P5 customers should not be required to continue to maintain their standby facilities or fuel.

24. The Commission should require that the utilities allow customers classified as P2A, qualifying under the annual economic feasibility test, to continue to establish this qualification on an annual basis.

25. The Commission should require that the utilities allow customers classified as P2A, with pending applications to be re-classified as noncore, to file their applications until August 1, 1991.

26. The Commission should require that the utilities not accept applications of P2A customers desiring to be reclassified as noncore after August 1, 1991.

27. The Commission should require the utilities to maintain a list of P2A core customers wanting noncore status and of their historical volumes for cost allocation purposes.

28. The Commission should allow the utilities to assess a $1/therm penalty on interruptible customers failing to curtail when requested to do so.

29. The Commission should allow the utilities to establish a tracking account for curtailment penalty funds not used to replace gas used by customers failing to curtail.

30. The Commission should permit the utilities to apply the curtailment penalty funds towards the installation of electronic meters.

31. The Commission should require the utilities to allow customers meeting the criteria for the alternate fuel program to install an electronic meter at their own cost to participate in the program.

32. PG&E should remove the phrase "unintentional and minor" in reference to imbalances.

33. PG&E should allow imbalance trading within the 10% tolerance band.

34. PG&E should be allowed to approve all trades under its imbalance trading program.

35. PG&E and SoCal should submit advice letters describing their electronic bulletin board programs and should prepare a trading form for Commission approval.

36. SDG&E should correct its Imbalance Trading Schedule to state that related costs shall be recovered from the participants.

37. SDG&E should allow a customer at least 20 days from the notice of any imbalance to make an imbalance trade.

38. SDG&E should establish a PC-based bulletin board to facilitate imbalance trades.

39. SoCal should clarify its Rule 30 to state that imbalances occurring in the same time period are eligible for trading.

40. SoCal should specify the time period for trading imbalances.

41. The utilities should submit separate advice letters outlining the program and bidding rules for sales of excess core gas to comply with the procurement decisions.

42. PG&E should maintain its description of excess sales gas to SoCal and SDG&E under its interutility tariff to accommodate daily balancing operations, but PG&E should make the distinction that this service is different from its program to provide sales of excess gas to all bidders.

43. SDG&E should maintain its description of excess gas supplies in its tariffs.

44. The utilities should correct any references of a one-year term commitment for core subscription service to two years in order to comply with the mandate of D.90-12-100.

45. The Commission should allow the utilities to modify their tariffs to extend the full requirements option to Service Level 3 customers.

46. PG&E should modify its schedule for service to long-term contract customers to provide that the Service Level 2 rate shall be one-half the difference between the current total rate and the SL-2 total rate plus 1.2¢/therm.

47. The Commission should allow the utilities to apply the 65% nomination restrictions on UEG and EOR customers under Service Levels 2 and 3 on a seasonal basis.

48. The Commission should allow the utilities to apply the 65% nomination restriction for EOR customers equally to those customers having long-term contracts with those customers not having long-term contracts.

49. The Commission should adopt SDG&E's proposal for it to have one procurement portfolio with three subaccounts, subject to future cost allocation and reasonableness review proceedings.

50. SDG&E should amend its core subscription tariff to reflect that service is available only under a two-year obligation.

51. SDG&E should file revised tariffs correcting the calculation of the use-or-pay penalty for core subscription service.

52. SDG&E should eliminate the termination clause of Schedule GPNC, Special Condition 5 subjecting the customer to a 12 month payment of procurement costs.

53. The utilities' tariffs and rules should specify that cogenerators will be provided notice of the UEG elections.

54. The utilities' tariffs should specify that cogenerators will have five business days from the close of the open seasons to finalize their elections.

55. The utilities' cogeneration notice should identify UEG volumes elected by service level and month, and should calculate the estimated transportation costs of these categories.

56. Utilities should not be required to specify in the tariffs the form of the cogeneration notice to be issued.

57. PG&E and SDG&E should file CGA tariff revisions consistent with Resolution G-2946, issued on April 24, 1991.

58. The utilities should provide cogenerators with information sufficient to understand the methods and calculations used to refashion the UEG schedules.

59. The utilities should submit worksheets to the Commission detailing the UEG rate design changes made to comply with D.90-12-100, in order to verify compliance with the currently adopted revenues, throughput, and cost allocations.

60. The utilities should file detailed worksheets of the changes to be implemented under the PG&E ACAP decision and the OII decisions as part of the supplemental filings made to comply with this resolution.

61. PG&E's Cogeneration Declaration should delete language requiring 12 months backbilling for noncompliance.

62. PG&E's Cogeneration Declaration does comply with D.91-05-007.

63. SDG&E should modify its tariffs to state that no cogeneration volumes will be curtailed before any UEG volumes within the same transmission and service levels.

64. SoCal should refile tariffs for SDG&E and Long Beach to comply with Decisions 91-02-022 and 91-02-046.

65. PG&E should modify its wholesale schedule to provide core capacity access proportional to wholesale customers' core load outside the 450 MMcf limitation for noncore customers.

66. The utilities should provide wholesale customers' noncore customers service either directly or through the wholesaler.

67. PG&E should attach detailed tables showing the changes made to wholesale rates from the January 1, 1991 attrition filings to those changes ordered under the ACAP and OII 86-06-005, comparing the previous wholesale rates and demand charges to the new values.

68. SoCal should file the monthly demand charges and volumetric charges applicable to The City of Long Beach (Long Beach) as authorized by D.90-11-023 and the attrition filings and adopted by D.91-03-031.

69. SoCal should make an additional filing to incorporate any changes resulting from OII 86-06-005, and submit detailed workpapers showing the changes from January 1, 1991 through the OII's latest decision.

70. SoCal should rewrite its tariffs to allow Long Beach to have access to the El Paso and Transwestern pipelines on a pro rata basis with SoCal's core load.

71. SoCal should provide storage to Long Beach for its core service requirements.

72. SoCal and SDG&E should revise their Preliminary Statement language relating to core trigger mechanism to reflect D.90-12-100, Appendix A, page 3, and should update the references to reflect the most current ACAP decisions.

73. PG&E and SDG&E should remove the noncore trigger mechanisms from their Preliminary Statements.

74. PG&E should revise its calculation of the surcharge credit to reflect that the UEG transportation rate no longer contains demand charges, using the most recently adopted forecast adopted in its May 8, 1991 ACAP.

75. PG&E should not transfer any of the noncore portfolio balance to the core subscription PGA balance.

76. PG&E's and SoCal's noncore portfolio balances should be set aside as of July 31, 1991 for disposition in each utility's next cost allocation proceeding.

77. The utilities may distribute the forecasted or actual funds from surcharge (1.2 cents/therm) revenues at the end of a ratemaking period or monthly, as is prescribed by the procurement decisions.

78. The utilities should accrue interest on the tracking account balance, if actual funds are used to distribute the surcharge credit revenues.

79. The utilities should distribute the surcharge credit to those Service Level 3 through 5 customers paying the default transportation rate.

80. The utilities should distribute the surcharge credit to those Service Level 3 through 5 customers having negotiated transportation contracts only if the negotiated rate differential is less than the difference between the default rate and the surcharge credit.

81. PG&E and SDG&E should revise their tariffs to reflect that LUAP and GDU costs are associated with the transportation rate and not with the procurement rate or brokerage fees.

82. PG&E should refile its tariff removing in-kind shrinkage charges for its commodity charges and returning them to the transport rates.

83. PG&E's rates should be updated to reflect the adopted shrinkage factor from PG&E's most recent ACAP.

84. SDG&E should eliminate the unauthorized brokerage fee cap in its procurement filing, as well as the proxy brokerage fee.

85. SDG&E should include language in its tariff stating that its current brokerage costs are embedded in the gas portfolio WACOG.

86. SoCal and PG&E should charge a brokerage fee with the standby penalty for procurement services to noncore customers.

87. SDG&E should not charge a brokerage fee with the standby penalty for procurement services until a brokerage fee is approved.

88. SoCal should state in its tariffs that the 14% core subscription take-or-pay procurement penalty will vary with the posted WACOG, and that this value is a proxy until a cost-based rate can be determined.

89. SoCal should revise its tariffs relating to SL-2 full requirements customers' use-or-pay liability, clearly stating that this penalty will be applied if the customer burns alternative fuel with authorization.

90. PG&E should retain its current tariff for meter reads until it installs new meters providing daily reads, so that billing months for all its transport customers can coincide with calendar months.

91. PG&E should retain its current tariff for steam meters until the Commission changes the requirements.

92. The utilities should incorporate tariff language to state that buy-back and standby penalties assessed in error will be refunded.

93. The utilities should not relieve a customer of imbalance penalties due to a subsequent billing adjustment.

94. SoCal should include in its tariffs the provision that use-or-pay obligations for SL-2 and SL-3 are to be calculated on an annual basis.

95. SDG&E should update its cost allocation factors to comply with Appendices I and J of D.90-11-023.

96. SoCal should exclude the carrying cost of gas in storage from the calculation of interest.

97. PG&E should discontinue entries to the CSA Account as ordered by D.90-04-021 and its Preliminary Statement should eliminate any references to the CSA Account.

THEREFORE, IT IS ORDERED that:

1. Pacific Gas and Electric Company shall file revised tariff sheets in accord with the provisions of General Order 96A, consistent with each of the findings and conclusions listed above.

2. Southern California Gas Company shall file revised tariff sheets in accord with the provisions of General Order 96A, consistent with each of the findings and conclusions listed above.

3. San Diego Gas and Electric Company shall file revised tariff sheets in accord with the provisions of General Order 96A, consistent with each of the findings and conclusions listed above.

4. The utilities shall submit revised tariffs five days from the effective date of this resolution.

5. This order is effective today.

I certify that this Resolution was adopted by the Public Utilities Commission at its regular meeting on May 22, 1991. The following Commissioners approved it:

Neal J. Shulman

NEAL J. SHULMAN
Executive Director

PATRICIA M. ECKERT
President
G. MITCHELL WILK
DANIEL Wm. FESSLER
NORMAN D. SHUMWAY
Commissioners

Commissioner John B. Ohanian, being necessarily absent, did not participate.

APPENDICES

APPENDIX A
Page 1

GLOSSARY

LIST OF ACRONYMS AND TERMS

ACAP	Annual Cost Allocation Proceeding
ACQ	Annual Contract Quantity
BCAP	Biennial Cost Allocation Proceeding
Bcf	Billion cubic feet
Buy-Back	A penalty condition where a customer transports more gas than it nominates for receipt. The utility buys this extra gas at 50% of its current WACOG.
CGA	Cogeneration Gas Allowance
Core	Residential and small commercial gas customers receiving utility bundled services, having no alternative fuel capability, and assigned to priorities P1 and P2A.
Core-Subscription	Large commercial and industrial gas customers receiving utility bundled services.
ECAC	Electric Cost Allocation Clause proceeding
EOR	Enhanced Oil Recovery. Any operation which uses gas as a fuel to pressure or inject steam or hot water into a well to increase oil production from that well.
GDU	Gas Departmental Use
LUAF	Lost and unaccounted for gas
IER	Incremental Energy Rate
IHR	Incremental Heat Rate
In-Kind Shrinkage	A condition where the utility applies a percentage to the customer's transported gas quantity to account for the loss of its gas due to compression.
MCQ	Monthly Contract Quantity

MDth	One Thousand Decatherms
MDQ	Maximum Daily Quantity
MMcf/d	Million cubic feet per day
Noncore	Large commercial and industrial gas customers receiving utility transportation only services and having alternative fuel capability.
OII	Order Instituting Investigation
OIR	Order Instituting Rulemaking
P1, P2A	Priority 1, 2A (Core Gas Customers)
P2B, P3, P4, P5	Priority 2B, 3, 4, 5 (Noncore Gas Customers)
PGA	Purchased Gas Account
Schedule C-CIG	PG&E's Procurement Service for customer-Identified Gas
SL1	Service Level 1 (Transportation Service for Core Customers)
SL2	Service Level 2 (Firm Transportation Service for Noncore Customers)
SL3, SL4, SL5	Service Levels 3, 4, 5 (Interruptible Transportation Service for Noncore Customers)
Standby	A penalty condition where the customer has not transported sufficient gas to meet its demand and uses utility gas.
Take-or-Pay	A penalty condition where the customer does not use as much gas as it has stated it will use.
UEG	Utility Electric Generation
Use-or-Pay	A penalty condition where the customer does not require as much capacity as it stated that it needed.
WACOG	Weighted Average Cost of Gas

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PROTESTS

PG&E A.L. 1624-G

Date	Filed by	Reply Date
01/30/91	Brady & Berliner on behalf of Alberta Petroleum Marketing Commission (APMC)	02/07/91
01/30/91	Jackson, Tufts, Cole & Black on behalf of The Indicated Producers (IP)	02/07/91
01/30/91	Southwest Gas Corporation (Southwest)	02/06/91
02/07/91	TURN	02/28/91
02/08/91	Sutherland, Asbill & Brennan on behalf of The California Industrial Group, California Manufacturers Association, and California League of Food Processors, referred collectively as CIG	
02/11/91	Morrison & Foerster on behalf of The California Cogeneration Council (CCC)	03/12/91
02/11/91	Division of Ratepayer Advocates (DRA)	02/26/91
02/11/91	Ater, Wynne, Hewitt, Dodson & Skerritt on behalf of The Cogenerators of Southern California (CSC)	02/26/91

PG&E A.L. 1624-G(A)

04/09/91	Greve, Clifford, Diepenbrock & Paras on behalf of the State Department of General Services	04/22/91
04/15/91	Southwest	04/24/91
04/15/91	Brady & Berliner on behalf of APMC and the Canadian Producer Group	04/25/91
04/15/91	Morrison and Foerster on behalf of CCC	04/25/91
04/19/91	Sutherland, Asbill & Brennan on behalf of CIG	04/30/91

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PROTESTS

<u>SoCal A.L. 2009</u>

02/08/91	TURN
02/11/91	DRA
01/30/91	SDG&E
01/30/91	Southern California Edison Company
01/30/91	Patrick J. Power on behalf of The City of Long Beach
02/11/91	Sutherland, Asbill & Brennan on behalf of CIG
02/11/91	Morrison, Foerster on behalf of CCC
01/30/91	Jackson, Tufts, Cole and Black on behalf of IP
02/11/91	Ater, Wynne, Hewitt, Dodson & Skerritt on behalf of CSC

SoCal responded to the above protests on March 15, 1991.

<u>SDG&E A.L. 740-G</u>

02/11/91	Sutherland, Asbill & Brennan on behalf of CIG	02/26/91
02/11/91	Morrison & Foerster on behalf of CCC	02/26/91
02/11/91	DRA	02/22/91