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Decision 90 07 065 JUL 18 1990

ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking 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.	R.90-02-008 (Filed February 7, 1990)

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INTERIM OPINION

This decision proposes a set of rules for the regulation of the natural gas industry. We initiated this rulemaking in R.90-02-008 (OIR), issued February 7, 1990. R.90-02-008 set forth a framework for developing rules designed to resolve several problem areas in our existing regulatory program and to provide increased opportunities for competition and resulting consumer benefits.

In summary, the rules we propose today would require several changes to the existing regulatory program:

- Replace the existing core elect service with a "core subscription" service providing highly reliable gas service to noncore customers that make a commitment of two years or longer and accept a 75% take-or-pay obligation.

- Establish a firm transportation service for noncore customers that make a commitment of one year or longer and accept a 50% use-or-pay obligation.

- Eliminate the existing noncore portfolio.

- Limit core subscription purchases by electric departments of combined utilities to 15% of their annual requirements.

I. Background

On February 7, 1990, we issued R.90-02-008. The rulemaking proposed general changes to gas utility regulation. We issued the rulemaking after holding an informational en banc hearing in November, 1989 at which numerous parties presented their views about the status of the natural gas industry in California. Several of the parties identified what they believed to be serious problems, and recommended changes to our existing program.

R.90-02-008 proposed several options for resolving what we perceived to be problems with the current regulatory structure. We sought comments on our decision, and stated our intention to issue proposed rules based on those comments and then issue final rules.

On April 25, 1990, Southern California Gas Company (SoCal) filed a request for adoption of a settlement it had reached with several parties. The signatories to the settlement are SoCal, California Industrial Group, California League of Food Processors, and California Manufacturers Association (CIG), Mock Resources Inc. and Salmon Resources, Ltd. (Salmon/Mock), Toward Utility Rate Normalization (TURN), GasMark West, Inc. (GasMark), University of California and Enron Gas Marketing Inc. (Enron). SoCal's filing requested several changes to the procedural schedule in this proceeding, including suspending any action on R.90-02-008 until the Commission had issued a decision on the settlement. The request for procedural changes was denied by the assigned Administrative Law Judge (ALJ) in a ruling issued May 3, 1990. The ALJ ruling also provided that the period for commenting on the settlement would be extended from the 30-day period set forth in Rule 51.4 to the deadlines for comments and replies on this decision.

The settlement proposes several changes to the existing regulatory program. The signatories to the settlement describe the settlement provisions in their comments. The settlement provisions and the signatories' comments are addressed by issue below.

By April 27, 1990, the following parties filed or submitted comments:

AES Placerita Inc. (AES)
Alberta Petroleum Marketing Commission (APMC)
Bonus Gas Processors, Inc. (Bonus)
California Cogeneration Council (CCC)
California Department of General Services (DGS)
California Energy Commission (CEC)
CIG
Canadian Producer Group (CPG)

Capitol Oil Corporation (Capitol)
Carlton Forge Works (Carlton)
City of Long Beach
City of Palo Alto
Cogenerators of Southern California (CSC)
Division of Ratepayer Advocates (DRA)
El Paso
Enron
GasMark
Government of Canada
Hadson Gas Systems, Inc. (Hadson)
Holliday Rock Corporation, Inc. (Holliday)
Indicated Producers
McFarland Energy, Inc. (McFarland)
(Salmon/Mock)
Natural Gas Clearinghouse (NGC)
Natural Resources Defense Council (NRDC)
North Canadian Oils Ltd. (NCO)
Pacific Gas and Electric Company (PG&E)
Phillip Morris Management Corporation (Phillip Morris)
Phillips Petroleum Company, Phillips 66 Natural Gas Company, and Phillips Gas Marketing Company (Phillips)
Rockwell International (Rockwell)
San Diego Gas and Electric Company (SDG&E)
School Project for Utility Rate Reductions (SPURR)
Shell Oil Company (Shell)
Southern California Edison Company (Edison)
Southern California Gas Company
Southern California Utility Power Pool and Imperial Irrigation District (SCUPP)
Southwest Gas Corporation (Southwest)
State of New Mexico
Sunpacific Energy Management and Sunrise Energy Co. (Sunpacific)
Texaco and Texaco Gas Marketing (Texaco)
Toward Utility Rate Normalization (TURN)
Transwestern Pipeline Company (Transwestern)
Western Gas Marketing Limited (Western)

This decision does not summarize all of the comments of all of the parties because of their large number. The decision does, however, attempt to describe all perspectives and we propose these rules after considering all of the parties' views.

II. Industry Structure

A. Noncore Procurement Activities and Marketing Affiliates

The OIR proposed that gas utilities be prohibited from offering noncore procurement services (except those considered "core subscription" service, and in other specific circumstances, discussed below).

We further proposed that gas utilities seeking to continue noncore procurement activities should be permitted to do so only through unregulated, fully separate affiliates. We asked for comments regarding requirements which might be necessary to prevent potential self-dealing or cross-subsidization between affiliates.

We directed our attention to the issue of utility noncore procurement activities because of complaints we had received about the inability of noncore customers, producers, and marketers to effectively compete in the noncore market against gas utilities with firm access to pipeline capacity. We also heard complaints about utilities "bumping" and "trimming" noncore customers' gas in order to permit the utilities to sell their own higher priced supplies to the same customers.

1. Positions of the Parties

a. The Settlement

The settlement provides that procurement services to noncore customers will be retained, although utility gas sales to both the core and noncore would be made from a single portfolio. Noncore gas prices would be the same as prices to core customers except that they would vary monthly to reflect actual gas costs, and would be subject to a one cent per therm procurement charge. For PG&E, gas prices to noncore customers would differ from those charged to core customers to reflect a higher allocation of PGT gas to PG&E's core customers.

Utility procurement service would be available to noncore customers notwithstanding the type of transportation service they purchase. Customers would be required to make a commitment to purchase utility gas for one year or more, and agree to a 50% take-or-pay requirement. The take-or-pay charge would be 14% of the utility's WACOG until an amount is set in each utility's ACAP.

On the subject of marketing affiliates, the settlement states the agreement of the signatories that the Commission should adopt rules no less restrictive than those proposed in the OIR, and allows the parties to advocate whatever more restrictive rules they may deem appropriate.

b. PG&E

PG&E agrees with the OIR that the noncore portfolio should be eliminated. It argues, however, that it must have the option of establishing an unregulated affiliate to market noncore gas supplies in its territory. That affiliate, in PG&E's view, should not be burdened with gas supply contracts entered into before the Commission's final rules are issued.

c. SoCal

SoCal supports the Settlement provisions for gas sales to noncore customers. SoCal states it is not interested in establishing a new unregulated marketing affiliate. SoCal characterizes the prospects for such an affiliate as "lose-lose": it will either fail to make profits, or profit and become the subject of attacks claiming anti-competitive activity. Although SoCal does not plan to form a marketing affiliate, it states marketing affiliate rules should not apply to activities between the utilities and regulated affiliates which sell gas to the utilities. SoCal also comments that some affiliates would be outside the jurisdiction of the Commission.

d. DRA

DRA favors eliminating the noncore portfolio. It also asserts that utility marketing affiliates are not needed considering the large number of supplies competing for noncore sales. Because they are not needed, they should not be permitted so that the Commission may avoid the kinds of problems experienced with the unregulated affiliates of several other California utilities.

If the Commission permits the utilities to offer noncore procurement services through unregulated affiliates, it should carefully monitor utility activities to assure no self-dealing occurs. The Commission should assert its authority to require production of any information needed to investigate potential cross-subsidies between the regulated and unregulated businesses.

e. CEC

The CEC supports the OIR's approach on this issue, and also raises a concern that Commission access to affiliate records not hamper the competitiveness of the affiliates.

f. TURN

TURN, a consumer advocacy group, supports the Settlement's treatment of noncore sales. It urges the Commission to impose a ban on unregulated marketing affiliates except where they already exist. TURN believes permitting such affiliate activities invites trouble, citing the problems FERC is confronting with interstate pipeline marketing affiliates and Edison's dealings with its affiliated Qualifying Facilities (QF) in the electricity market.

g. Industrial Customers

CIG, a consortium of industrial customers, believes it would be appropriate during the initial three-year term of the new program to prohibit the gas utilities from establishing new marketing affiliates. The purpose of the prohibition, according to

CIG, would be to allow competing suppliers to gain a foothold in the market without having to compete with affiliates which may have an inherent competitive advantage.

h. Pipeline Companies

El Paso, an interstate pipeline company serving both SoCal and PG&E, supports the Commission's proposal to require separation of utility noncore procurement functions from core utility operations. El Paso proposes that the Commission use the guidelines for marketing affiliates set forth in FERC Order No. 497.

i. Independent Gas Producers and Marketers

Gas producers and marketers generally agree that utility noncore portfolios should be eliminated. They express concern with the potential for anticompetitive activities by affiliates but most do not oppose the creation of such affiliates. Salmon Mock suggests that if the Commission permits affiliates to sell gas, it should apply the guidelines it adopted in D.88-01-063 for an electric utility and its unregulated affiliates.

GasMark believes California ratepayers would be best served by prohibiting utilities from establishing unregulated marketing affiliates. If the Commission does permit such affiliates, GasMark suggests strict protections against self-dealing and discriminatory practices.

Indicated Producers, a consortium of natural gas producers, expresses concern with unregulated affiliates and urges the Commission to review its rules a year after implementation to assure that they provide intended protections. Indicated Producers also states the Commission should direct that no portion of the regulated utility's interstate capacity rights should be transferred to the marketing affiliate. Affiliates should be treated like any other marketing firm. Like SCUPP, Indicated Producers suggests the Commission adopt FERC's rules for marketing affiliate relationships.

j. DGS

DGS supports the Settlement's treatment of utility procurement with some modifications. Specifically, DGS argues the Commission should reduce the Settlement's $.01 per therm brokerage fee to actual cost, and adopt a price that does not vary every month. Generally, DGS believes the Settlement would permit the utilities to continue to sell gas to the noncore market, which DGS believes is preferable to the OIR's approach.

DGS recommends that if the Commission does not permit the utilities to sell noncore gas, they should not be able to create unregulated subsidiaries to sell gas within their service areas because of the inherent conflict of interest which would occur.

k. Cogenerators

CCC supports the elimination of the noncore portfolio. It comments, however, that such action will affect the way utility payments to QFs are calculated because those payments are based in part on the noncore weighted average cost of gas (WACOG) for SoCal and SDG&E. CCC urges the Commission to designate in this proceeding the benchmark for establishing avoided costs so that the matter does not become the subject of haggling in various other proceedings.

CSC also raises the concern regarding developing avoided cost absent the benchmark currently provided by the noncore WACOG. CSC urges the Commission to address the issue in this proceeding, in order to avoid the uncertainty which would otherwise result for cogenerators. It suggests the Commission apply the UEGs' actual gas costs in developing avoided costs as a reasonable and easily verified alternative to the noncore WACOG.

l. UEG and Wholesale Customers

Edison, Long Beach, Southwest, SCUPP, SDG&E and Palo Alto agree with the OIR that the utilities should not offer noncore supplies.

SCUPP, representing several Southern California utility wholesale customers, suggests the Commission adopt requirements analogous to the FERC's regulations governing the conduct of affiliated transactions.

2. Discussion

The parties are divided on whether the utilities should be able to market noncore supplies. Most generally agree with the OIR that the utilities should not participate in noncore procurement markets. Settlement proponents believe the OIR is too restrictive and argue in favor of an unbundled gas service whereby noncore customers could purchase the gas commodity out of a single utility portfolio.

R.90-02-008 made clear our intent to reduce the utilities' role in procurement markets because of the potential for anticompetitive activity. The terms of the Settlement seem at first glance to eliminate noncore procurement by eliminating the noncore portfolio. On closer consideration, however, the Settlement would continue the utilities' noncore procurement activities: under the Settlement, the utilities would eliminate their noncore portfolios but offer the same type of service through the core portfolio. This provision not only retains unbundled gas sales to noncore customers, it expands the utilities' role in the noncore market by allowing them for the first time to sell gas subject to long-term agreements.

In general, the Settlement proposes service options for noncore customers that are unlikely to adequately reduce utility sales to customers who have competitive options. Section II.B of this decision discusses in greater detail our views on the objectives of core subscription and the appropriate role of the utilities in providing services to noncore customers. To promote a more competitive noncore gas market, we will order the utilities to eliminate their noncore procurement operations.

The subject of marketing affiliates is more difficult. PG&E strongly favors discretion to create marketing affiliates in the immediate future. SoCal states it would not create a marketing affiliate, believing marketing affiliates would present it with too much risk, either from a profit standpoint or because of the potential for unfavorable public perceptions and potential legal challenges. Several parties, including DRA, CIG, and TURN, oppose the creation of utility marketing affiliates, at least during the initial stages of any new regulatory program. Somewhat curiously, parties that might compete with utility marketing affiliates express concern with the potential for anticompetitive activity by utility affiliates but do not recommend that we prohibit them.

The question of whether utility gas marketing affiliates should be permitted turns on whether the benefits of their participation in gas markets outweigh the risks. The risks are several. As we have said many times, improper transactions between utilities and their affiliates may cause captive ratepayers to subsidize an affiliate's participation in a competitive market. These activities are in turn anticompetitive because affiliates may offer services at prices below costs. A utility could also use its monopoly position to discriminate against competitors seeking access to transportation. We are aware of abuses by interstate pipelines and their marketing affiliates and the FERC's efforts to control them. We, too, have addressed the issue of improper transactions between other California utilities and their unregulated affiliates in various formal proceedings.

As DRA points out, procedures for protecting against improper transactions between affiliates and utilities are burdensome for regulators, requiring complex audits and oversight. Fair and proper allocation of costs between affiliates and utilities presents a difficult regulatory challenge. Monitoring utility access practices would require substantial effort with uncertain results.

Keeping in mind the risks presented by marketing affiliates, we consider the potential benefits which might result from affiliates' participation in the gas procurement market. The parties who commented in this proceeding did not discuss how utility affiliates might benefit the industry or California consumers. We can only speculate that PG&E may wish to create a marketing affiliate because it believes it can profit from the endeavor. PG&E's unregulated profits are not a concern of ours, however.

As several parties have commented, the utilities' participation in the noncore procurement market is not needed to assure noncore customers are able to purchase gas. A competitive gas supply market has developed which appears to be adequate to serve all noncore customer needs. We will, therefore, propose to prohibit the utilities from creating new marketing affiliates for the time being. Affiliates would present too much risk and are not required to assure a reliable source of gas supplies for noncore customers.

TURN reminds us that the utilities have existing marketing affiliates and recommends that the Commission should not prohibit their procurement activities. Under existing circumstances, it would be difficult to require that the utilities end their associations with their affiliates. Alberta and Southern (A&S), for example, brokers all of the gas PG&E purchases from Canadian producers under contracts which are still binding. As we discuss in Sections B and C, we believe the relationship between A&S, PGT, PG&E and Canadian producers has created a problem for California consumers; however, PG&E should not be required to end its corporate relationship with A&S at this time. It should, however, be required to end its preference for A&S gas supplies when current contracts expire. We address PG&E's relationship with A&S in more detail below.

If we require the utilities to eliminate the noncore portfolio, we must also establish a benchmark for calculating payments to QFs. This issue should be resolved, however, in a forum where related issues are under consideration. We will consider it in Phase III of I.89-07-004 in which we are reviewing utility resource planning and changes to avoided costs.

In conclusion, we propose to prohibit the utilities from procuring noncore gas, and from creating new noncore marketing affiliates. Our proposed rules on this issue are as follows:

> The gas utilities shall not sell gas supplies to noncore customers except those which subscribe to core services and as permitted under other rules.
>
> The utilities shall not create new noncore marketing affiliates. The utilities shall show no preference for their own affiliates' gas supplies, except as required to fulfill pre-existing contract obligations, and shall treat those affiliates as they would any other gas supplier. PG&E's preference for A&S supplies shall end when its existing contract obligations end.

B. <u>Core Services for Noncore Customers</u>

The OIR proposes to eliminate the current core-elect option and replace it with "core subscription" service. We asked the parties to comment on our proposal to make core subscription service one which would be offered to noncore customers who make a service commitment of three to five years and accept a 50 to 80% take-or-pay obligation. The OIR proposed that rates for core subscription service would include the core WACOG and the core transportation rate.

Core subscription service would be bundled: customers who purchase it would receive both procurement and transportation services. We did not propose a separate "core" transportation service which would provide firm access to pipeline capacity. We stated that the issue of firm service would be addressed in

R.88-08-018, where we are reviewing pipeline capacity allocation programs.

The core-subscription service was motivated by our view that some noncore customers may not wish to arrange for gas service through a competitive market and should be able to purchase a reliable utility service instead. Some parties believed the existing core-elect service had attracted too many noncore customers in PG&E's territory, giving PG&E exclusive access to Canadian gas and a substantial advantage over other competitors in the noncore market.

1. <u>Positions of the Parties</u>

a. <u>The Settlement</u>

The Settlement provides that procurement and transmission services to noncore customers would be unbundled, as discussed in Section II.A. The Settlement provides that in addition to providing noncore procurement service, the utilities would offer noncore customers a highly reliable core-elect transmission service. The service would be subordinate in priority only to P-1, P-2A, P-2B, cogeneration and Tier I UEG customers. The rate for this service would be tariffed and nonnegotiable.

Interstate capacity, under the terms of the Settlement, would be available to noncore customers, subject to recall for core requirements. Until capacity brokering is in place, the utilities and noncore customers would enter into "buy/sell" agreements whereby a customer would identify gas supplies which the utilities would purchase and resell to the customer. For SoCal, the capacity available on the Transwestern and El Paso lines would be retained for core customers on a pro rata basis. For PG&E, the maximum PGT capacity core customers would be entitled to would be equal to average year requirements less the capacity required to move California produced gas purchased by PG&E. Noncore customers would be entitled to a pro rata allocation of remaining capacity on the PGT and El Paso systems.

b. <u>PG&E</u>

PG&E proposes to offer a bundled core subscription service. Under its proposal, all noncore customers would be eligible to purchase it. Core subscription would be the default service for noncore customers who consume less than 1.5 million therms annually. These smaller customers would be permitted, within the first six months of the program, to switch from core subscription to an unbundled service.

Under PG&E's proposal, core subscription would receive highest priority after P1 and P2A customers. The transportation component of the bundled rate would be the same rate charged to nononcore firm transportation customers. Core and core subscription customers would pay the same price for the gas commodity. PG&E believes a reasonable take-or-pay requirement is 80% with a three- to five-year commitment and a one-year written cancellation notice.

PG&E also proposes to provide 300 MMcf/d of firm intrastate and interstate transmission capacity of a year-round basis for noncore customers who do not purchase gas from the utility. The capacity would be split evenly between PGT and El Paso and would be subject to interruption only if necessary to avoid curtailment of P1 and P2A customers. This transportation service would be given the same priority as core subscription service.

To implement this firm service, PG&E proposes to use a buy/sell type arrangement to provide noncore customers access to Canadian gas until capacity brokering is implemented on PGT. Noncore customers would be limited to purchases from the A&S producer pools until PG&E's prepayment and other supply obligations are worked down or restructured. PG&E would pursue buy/sell type arrangements on the El Paso system also until capacity brokering is implemented. PG&E intends that the total volume of firm capacity will remain fixed until a capacity brokering program is put into place, new capacity from Canada is available, and PG&E has had time to restructure its supply arrangements with Canadian suppliers.

PG&E proposes that core subscription and noncore firm customers would pay the same firm transportation rate. Lower rates would be set for interruptible service.

c. SoCal

SoCal is critical of the Commission's proposal to bundle high quality transportation service with a core procurement service. SoCal comments that core subscription customers would have to pay about $.20 a therm more transmission service for the privilege of buying gas supplies from the utility even though core subscription customers' service priority would be below that of P1 and P2A customers. The OIR, according to SoCal, is wholly inconsistent with the Commission's well-established policy of unbundling services. SoCal believes the noncore customers procurement decisions should be independent of their transportation service decisions. SoCal also believes the time commitment and take-or-pay levels in the OIR are unnecessarily harsh.

SoCal describes the Settlement's provisions as "substantially superior" to those set forth in R.90-02-008. The Settlement, according to SoCal, is preferable to the OIR proposals because it does not require customers to commit to such long-term supplies. Consequently, they are not required to predict the level of demand for their products so far into the future, and are not liable for events which are beyond their control.

SoCal believes the core-elect transmission service presented in the Settlement is preferable to the core subscription transmission service proposed in the OIR because it would be priced lower than the core transportation rate, thereby recognizing cost and service differentials. Use-or-pay obligations would apply only if the customer switched to an alternate fuel.

d. DRA

DRA supports the Commission's proposal to offer a new bundled core service. It recommends that the service be priced according to the utility's cost of gas plus a tariffed rate for firm delivery transmission service. DRA suggests the Commission review cost allocation and rate design issues in I.86-06-005 where the Commission is considering costing issues. If core subscription is implemented prior to a new rate structure in that proceeding, the Commission could place an interim surcharge on existing noncore transportation rates to account for the higher quality of service.

DRA proposes that the minimum subscription period be five years to allow the utilities to forecast service obligations. DRA also recommends a 75% take-or-pay requirement to minimize utility and ratepayer risk.

e. CEC

The CEC expresses strong support for the OIR's proposed treatment of noncore procurement and core subscription.

f. DGS

DGS suggests that the core subscription service as described in the OIR is discriminatory and unreasonable because other core customers are not required to sign long-term agreements or submit to take-or-pay obligations. DGS recommends that any new system that eliminates the utilities' role in noncore procurement should assure the development of a functioning brokering system.

g. The Government of Canada

The Government of Canada states the OIR proposals will threaten market relationships between Canadian suppliers and California utilities. Gas supplies from A&S have been characterized by the Commission as providing California customers with "reliability, stability and current competitiveness" as recently as 1988.

Alberta Petroleum Marketing Commission (APMC) is the agency of the government of the Province of Alberta which represents the interests of Alberta in gas and oil regulatory proceedings outside the province. Generally, APMC is concerned that the OIR does not sufficiently address the need for coordinating regulatory developments in the U.S. and Canada, or the need for new capacity to achieve the Commission's objectives. APMC offers several insights into the contractual relationships between PG&E and Canadian suppliers which it believes should be considered in any regulatory restructuring in California. Specifically, APMC comments that Canadian supplies have been impeccably reliable and that renegotiation between Canadian suppliers and PG&E should not be required.

h. UEG and Wholesale Customers

SDG&E supports the establishment of unbundled firm and interruptible transmission services. SDG&E believes demand charges are preferable to take-or-pay and three- to five-year obligations. It expresses concern with the loss of control of its noncore throughput.

Edison comments that the OIR's approach will not resolve the problems the Commission has observed unless the Commission removes barriers to customers obtaining firm pipeline capacity.

For the core subscription service, Edison supports an 80% take-or-pay obligation so that core customers do not reserve excess capacity. Edison does not believe that the core subscription service outlined in the OIR will serve the Commission's objective of removing PG&E's monopoly control over access to Canadian gas. Finally, Edison recommends that the Commission establish a firm transmission service for noncore customers and UEG igniter fuel requirements.

Palo Alto agrees that a core subscription type service should be offered. It comments, however, that core subscription should not be considered a substitute for the rights previously granted to wholesale customers for core load management, including firm transportation service. It urges the Commission to create a "wholesale subscription" service under which the utilities would provide firm transportation, storage and balancing services equal to those provided to primary utilities for core load management. Palo Alto comments that this wholesale service would have a priority equal to that of P1 and P2A customers in order to maintain existing end use priorities. Accordingly, wholesale loads would receive a priority ahead of the core subscription category proposed in the OIR.

Long Beach generally agrees with the OIR's approach to develop a core subscription service. It comments, however, that some noncore customers may seek the option of buying firm bundled services from competing gas suppliers. The Commission, according to Long Beach, should direct the gas utilities to provide such a service.

Like Palo Alto, Long Beach expresses great concern that any changes in the Commission's program should recognize that wholesale customers serving core markets should retain rights to whatever facilities are reserved for SoCal's (and PG&E's) core gas requirements. Long Beach raises several issues regarding wholesale customers which it believes are not addressed in the Settlement, mainly concerning the status of long-term contracts and core elect transmission for wholesale customers.

SPURR urges the Commission to direct the utilities to offer core transmission service as the most effective means of maintaining reasonable gas costs for the core.

Southwest comments generally that the Commission should consider the position of local distribution companies like Southwest, which are downstream from gas utility suppliers and which have core customers of their own. Southwest expresses concern that it be able to retain firm transportation for its core gas customers and may, as a supplier to core customers, need greater flexibility than other noncore customers. It recommends that downstream utilities not be subject to long core-elect commitments, suggesting a one-year commitment would be optimal.

i. TURN

TURN supports the settlement's provisions for procurement and transmission services, commenting that core-elect services should not only act as a "safety net" for noncore customers, but should be considered a means of improving the load factor and price sensitivity of the core portfolio. Eliminating core-election could, according to TURN, have damaging effects on California's relationship with PG&E's traditional Canadian suppliers, to the detriment of core customers.

j. Cogenerators

CCC urges the Commission to expand the priority status of cogenerators for intrastate pipeline transmission to interstate services. Cogenerators' priority on the intrastate system should be matched by similar protections on the interstate system in order for the Commission to fulfill the intent of Section 454.7. Under that section, the Commission has acknowledged cogenerators' right to receive "the highest possible priority for the purchase of natural gas."

CSC and AES also urge the Commission to preserve end-use priority and parity rights of cogenerators under any new set of rules, as required by Sections 454.4 and 454.7. CSC generally supports the Commission's core subscription proposal.

k. Independent Producers and Marketers

Indicated Producers generally support the thrust of the Commission's core subscription proposal. It recommends a three-year commitment and a 75% take-or-pay obligation, which would be subject to a shortfall penalty of 30% of the core WACOG. Demand charges to core subscription customers, according to Indicated Producers, should be the same as those paid by core customers because the services will be virtually equivalent.

In addition to the matters addressed by the OIR, Indicated Producers suggests the Commission address the issue of producers, marketers, and brokers obtaining intrastate transmission contracts on their own accounts to serve noncore customers. Indicated Producers states such a program would allow competitors to offer the same wellhead-to-burnertip package currently offered by the gas utilities. Indicated Producers does not suggest that its proposal would interfere with any end-use priority scheme and recommends the Commission direct that the end-use priority of gas transported under a supplier's contract must correspond with the priority of the customers who receive the gas.

Finally, Indicated Producers emphasizes the new capacity and release of excess interstate capacity back to the pipelines as a crucial element of fostering competition in California gas markets.

GasMark suggests that small industrial customers be given the opportunity to wait and observe the operation of the marketplace before having to make a commitment to core subscription. It presents one option for providing such an opportunity whereby customers would have some period for moving in and out of the core portfolio without penalty, after which time the customer would have to commit to a three-year period.

Enron and Capitol support the Commission's intent to order the utilities to maintain a single core portfolio at a single price. Transmission rates, according to Enron, should be the same for similarly situated noncore customers.

Texaco, a gas producer in California, believes many of the problems the Commission is seeking to address will be mitigated by new capacity and a capacity allocation program. On the issue of core subscription, Texaco recommends that the take-or-pay requirement be applied on an annual, rather than monthly, basis. Texaco also urges the Commission to adopt a rule prohibiting the utilities from abrogating pre-existing long term contracts under any future capacity allocation scheme.

Salmon/Mock supports the concept of a core subscription service with a five-year commitment and an 80% take-or-pay obligation.

Phillips supports changes to core services to noncore customers. Phillips urges the Commission to provide an opportunity for noncore customers to offer core equivalent service by requiring the utilities to provide access to firm transportation.

Speaking for several Canadian producers, CPG expresses concern with the parameters for core subscription service. Generally, CPG states that core subscription service requirements should match the terms and conditions the utility must offer its suppliers. According to CPG, the three- to five-year time limit and the take-or-pay requirements do not reflect the commitments faced by the utilities.

CPG asserts the Commission does not have evidence to determine whether noncore customers prefer to purchase supplies from third parties rather than the utilities, and suggests a survey be undertaken.

NCO, a Canadian energy producer and marketer, believes "buy-sell" type arrangements, such as those which are likely to develop if utilities are to utilize their interstate capacity on behalf of individual customers, are unlawful. Market uncertainty would, according to NCO, would result from conflict between FERC and the CPUC. The Commission should therefore avoid buy-sell agreements. Like CPG, NCO argues that take-or-pay and term commitments for core subscription should match the commitments the gas utilities have made to their suppliers.

Bonus is a Canadian gas marketer that supports the elimination of core-election in order to open up PGT to competition. Bonus argues that the fact that PG&E may be subject to take-or-pay penalties if PGT is opened up is evidence that A&S gas prices are higher than the Canadian market price: otherwise A&S could use the access to PGT as a marketing opportunity.

l. <u>The State of New Mexico</u>

The State of New Mexico supports the OIR's proposal to phase out the gas utilities' role in noncore procurement and the notion of a core subscription service.

m. <u>Pipeline Companies</u>

El Paso generally supports the notion that customers requesting core service should be required to commit to at least three years of service, with a take-or-pay obligation of at least 50%.

Transwestern supports the approach taken in the OIR assuming that customers who commit to the subscription core option will be required to make certain price commitments with respect to the cost of gas. According to Transwestern, they should receive secure transportation services at some rate other than the charge attributable to the transportation element of the bundled core service charge.

n. <u>Industrial Customers</u>

Industrial customers do not consistently support the proposals in the OIR which address procurement and transmission services. CIG believes the Commission's proposal to replace the core-elect service with a core subscription service is seriously flawed. CIG suggests that the associated transportation element of the bundled rate is too high because it would be set at the same level as that offered to small core customers whose costs are much higher than those imposed by noncore customers. CIG argues the three- to five-year commitment is unreasonable unless it is offered with a transmission rate that is fixed over the same term.

CIG comments that the Settlement's provisions for take-or-pay are preferable to those proposed in R.90-02-008 because take-or-pay obligations should not be imposed on customers whose reduced demand results from weather, business conditions, conservation or any other factors except the use of alternate fuels. It also believes noncore customers need to have the option of a firm (core-elect) transmission service.

Philip Morris recommends a two-year commitment for core subscription service, with yearly renewals allowed thereafter, in order to allow for changes in customers' industrial operations. Noncore customers should be permitted to purchase only a portion of their gas requirements from the utilities, with a take-or-pay obligation equal to 50% of its total annual core gas requirements. The take-or-pay obligation should, according to Philip Morris, be suspended in the case of force majeure, and a make-up period should be allowed for gas paid for but not taken.

Holliday, Rockwell, and Carlton believe the OIR proposals will increase gas costs. Carlton adds that the three- to five-year commitment for core subscription is far too long.

Shell recommends continued unbundling of utility services with contract terms of no greater than one year.

2. Discussion

The purpose of the core subscription service should be to provide a premium service for noncore customers who place a high value on reliability for all or a portion of their gas requirements. Core subscription should be a service for customers willing to make a commitment to the utility in trade for a reliable service that will require little or no effort on the customer's part. The customer's commitment will in turn reduce utility risk and improve operational and financial planning.

Most parties agree that some type of core service should be offered to noncore customers but appear to differ on the purpose the service should fulfill. TURN believes the core subscription service should be used to increase or improve load, an objective we have adopted in the past. Industrial customers, on the other hand, view core subscription as one of a number of service options which should be flexible and cheaply priced.

In our view, the purpose of the core subscription service is not to provide noncore customers with access to utility gas supplies when they happen to be priced comparatively low, and we do not intend to design the service to encourage subscription to the core. Customers who seek the maximum flexibility and lowest prices may shop for low cost gas supplies and subscribe to interruptible transportation services. Neither should core subscription be designed to increase utility loads. As discussed in greater detail below, we believe the best interests of consumers are served by competitive gas markets rather than markets in which a single utility and its affiliates dominate buying and selling.

SoCal is correct that the OIR proposes a core subscription service which is inconsistent with the Commission's general policy of unbundling utility services. We have in recent years directed the utilities to unbundle services in order to provide additional competitive options. The purpose of the core subscription service, however, is not to provide customers with yet another competitive option. Our intent is to eliminate to the extent practical the utilities' participation in the noncore procurement business while providing a high quality service for noncore customers that do not seek competitive options. We continue to prefer a bundled service for noncore customers seeking to purchase gas supplies from the utilities and will address competitive goals by way of other policies.

Given our objectives for core subscription services, the Settlement's proposals for utility noncore services are unappealing. They would require minimal customer commitments--for gas and transportation services, one year with a 50% take-or-pay (for transportation, use-or-pay) obligations. Firm transportation would be priced at the same rate that now applies to a lower quality transportation service. In general, the Settlement's terms would encourage noncore customers to subscribe to core service, and would allow them to move in and out of the core too frequently.

We favor a core subscription service for noncore customers which requires a greater commitment by the customer. DRA proposes a core subscription service with a 75% take-or-pay provision and a five-year time commitment. PG&E proposes a core subscription service with an 80% take-or-pay obligation and a three-to five-year time commitment.

Although PG&E and DRA's proposals are more consistent with our objectives, we agree with industrial customers that a three- to five-year commitment may require too much of noncore customers, at least in the first years of our the program. A two-year period provides the utilities with some predictability without imposing an onerous forecasting burden on noncore customers. We will, therefore, propose a two-year commitment for subscription to the core.

A 75% take-or-pay obligation is reasonable, especially in view of the minimal two-year time commitment. A reasonable take-or-pay penalty is the full transportation rate plus 20% of the core weighted average cost of gas (WACOG). The Settlement also proposes that core subscription customers should be relieved of take-or-pay obligations which arise for reasons other than switching to alternate fuels or energy sources. This Settlement provision would impose risk arising from variable industrial customer demand on other core customers. We will not impose this additional burden on core customers.

Neither do we propose to adopt the recommendation of PG&E and GasMark to make core subscription effectively a default service for smaller noncore customers. We believe all noncore customers are capable of choosing their preferred gas service and should be required to do so within a reasonable period.

As several parties propose, core subscription transportation should have priority over all transportation services except the core. Curtailment within the core subscription class should be according to existing end use priorities.

CIG is correct that the firm transportation rate should not be priced equal to the core transportation rate because core distribution costs are likely to be higher than those for large customers. On the other hand, the Settlement's proposal to set the firm transportation rate equal to the existing transportation "default" rate is equally unappealing. The cost and value of firm service is likely to be substantially higher than the existing service which is interruptible. Until we have resolved these cost issues in I.86-06-005, we will require the utilities to set the firm transportation rate for core subscription equal to 125% of the interruptible rate.

Our proposed rule for core subscription is as follows:

> Each gas utility shall offer a core subscription service. That service shall provide to qualified noncore customers both gas and transportation for gas. Core subscription customers' gas shall have highest priority transportation after core customer gas. Curtailments of transportation among core subscribers shall be according to existing end use priorities. Core subscription customers' cost of gas will equal that offered to core customers. Core subscription customers' cost of transportation will be equal to 125% of the utility's interruptible transportation rate prior to the issuance of a cost allocation and rate design decision for each utility.
>
> In order to qualify for core subscription, customers must make a two-year commitment for 75% of their nominations. Take-or-pay penalties shall be equal to the transportation rate plus 20% of the core weighted average cost of gas (WACOG). Take-or-pay penalties shall apply when, for any reason except bankruptcy, customers take less than their nominated gas volumes.

> The initial offering of core subscription service shall provide noncore customers at least two notices of the changes in utility services. The first notice shall be mailed within five days of the effective date of the utility's tariff amendments. Noncore customers shall have 120 days from the date the first notice is mailed to inform the utility of their intention to subscribe to core service. The utility shall make all reasonable efforts to solicit the customer's response. If the customer has not ordered core subscription service within 120 days of the mailing of the first notice, the utility will designate the customer as a noncore customer. The customer will retain its pre-existing service prior to receiving a service under the new tariffs or prior to the end of the 120-day period, if the customer does not respond to the utility's notice.

The parties convince us that some type of firm transportation for noncore customers is required at least until the utilities have implemented capacity brokering programs. We will, therefore, propose that the utilities establish firm transportation which will have highest priority after core and core subscription volumes.

Noncore firm transportation should be priced to reflect the higher quality of service. We propose it be priced equal to 120% of the rate for interruptible service until we have approved a new rate design for the utilities' transportation services. Firm and interruptible rates shall be set in the meantime to permit the utilities to recover the revenue requirement set for the existing noncore transportation service.

Curtailment of noncore firm transportation customers should be according to existing end use priorities at least until the utilities have implemented capacity brokering programs. Pro rata curtailment may better serve our goals of letting markets determine which customers value services most highly. Such a curtailment policy may not be realistic, however, until customers are able to bid for pipeline capacity in a brokering program.

We also believe some conditions of service should be required for firm transportation service in order to improve utility planning capabilities and to assure customers really intend to use and pay for firm transportation. It is reasonable to require a one-year commitment for firm transportation, as proposed by the Settlement, and to impose a 50% use-or-pay obligation. Rates for this service should be non-negotiable. Finally, we would reconsider the desirability of this transportation service in the context of final capacity allocation programs being considered in R.88-08-018.

Among the most difficult issues in this rulemaking is that of PG&E's use of its PGT line to Canada. PG&E has retained exclusive use of the PGT line because of its high core demand. PG&E's demand is high because it has a substantial number of core elect customers, including its UEG department. Although Canadian gas is priced competitively with gas from other sources, we are convinced that Canadian gas prices would fall if additional buyers and sellers had access to transportation. This access may also have a secondary effect of putting downward pressure on prices for southwest gas.

In its comments, PG&E proposes to provide 150 million cubic feet per day (Mmcf/d) of PGT capacity to noncore customers. At this time, we cannot determine whether any particular amount of capacity is appropriate. Our first concern is for core customers, which should have first priority on the PGT line or whatever system offers the best combination of economic and reliable gas supplies to core customers. Our proposed rules will reflect this view.

Our proposed rules will also require PG&E to make available to noncore customers all PGT capacity which is not reserved for core requirements. Although we will not require PG&E to relinquish any specific level of PGT capacity to noncore customers, we believe our proposed rules today will provide ample PGT capacity to noncore customers by reducing PG&E's core demand significantly.

Under the rules we propose in today's order, customers wishing to move gas over PGT would engage in buy/sell arrangements for gas supplies from A&S until PG&E's minimum contract obligations are fulfilled in each purchase period defined in the contracts (that is, if minimum takes are on a monthly basis, noncore customers must purchase under the A&S contracts until minimum requirements are fulfilled for the month).

We reluctantly propose that customers must purchase from PG&E's brokering affiliate in recognition that PG&E has contract obligations which may be binding over the short term. This circumstance thwarts efforts to increase competition for Canadian gas. For several years, we have sought to move the gas industry in the direction of more competition. During this period, PG&E appears to have done little to relieve itself of contract obligations which stifle efforts to increase access to Canadian supplies and which may keep prices high for all customers.

Because PG&E has entered into contract obligations which preclude competitive access to bottleneck facilities, and because we suspect the contract prices are substantially higher than Canadian market prices, we expect the A&S contracts to be renegotiated. Renegotiated contracts should provide for reduced minimum takes and improved flexibility. Consideration for these concessions shall not be higher prices to core customers. Contract renegotiation should be complete by December 31, 1991. After that time, we will be predisposed to allocating to PG&E's shareholders the costs of existing contract obligations which ratepayers would otherwise bear or which would require continued purchases by noncore customers from A&S. In any event, the price PG&E pays for Canadian gas will be subject to scrutiny in PG&E's next reasonableness review.

Finally, we understand that the FERC issued a decision on January 24, 1990 which found that PGT's minimum bill provisions were no longer reasonable. (Pacific Gas Transmission Company, 50 FERC 61,067.) We will require PG&E to comment on the effects of this order on take-or-pay obligations with Canadian producers and invite other parties to comment on the order.

Our proposed rules for transportation services are as follows:

> Core customers shall have highest priority on all interstate and intrastate pipelines. Allocation of pipeline capacity to core customer needs shall be on the basis of least-cost gas purchasing strategies for all utilities.
>
> The utilities shall make available to noncore transportation customers all capacity on their systems which is not reserved for core customers. The gas utilities shall provide both firm and interruptible interstate and intrastate transportation services to noncore customers. The service shall provide highest priority transportation service after core and core subscription service.
>
> Noncore customers using the PGT line shall purchase gas from PG&E's affiliate A&S until PG&E's minimum contract obligations are fulfilled. PG&E shall notify the Commission and its customers when such obligations are met, and shall notify the Commission no later than December 31, 1991 of the status of A&S negotiations with Canadian producers.
>
> The rates for interruptible and firm transportation shall together allow the utilities to recover the revenue requirement set for the existing transportation "default" rate prior to the time the Commission approves a rate design for transportation services. The rate for firm transportation shall equal 120% of the interruptible transportation rate until the Commission has approved a rate design for the service. Rates for firm transportation service shall be tariffed and nonnegotiable.

> Initial allocation of noncore firm capacity shall be based on customers' pro rata share of nominations, and the reasonableness of nominations shall be confirmed by considering historical demand. Pro rata allocation shall not apply to customer volumes which are the subject of long-term contracts. Customers with long-term contracts that wish to use firm transportation service will be allocated firm transportation according to their pro rata shares of historical usage excluding contracted volumes.
>
> Firm transportation customers must make a one-year commitment to receive the service and accept a 50% use-or-pay obligation. Use-or-pay obligations will be imposed notwithstanding the reasons for reduced demand, unless the customer is subject to the jurisdiction of a bankruptcy court.
>
> At least until such time as the utilities have implemented capacity brokering programs, curtailments of firm transportation service shall be according to existing end use priorities.
>
> The utilities may transport gas to other utilities in order to assure operational flexibility on utility systems. By April 1 of each year, the utilities shall file with the Commission Advisory and Compliance Division estimated capacity allocation between core and noncore customers on each interstate pipeline.

Finally, we address the recommendation of Indicated Producers to permit producers, marketers, and brokers to obtain intrastate transmission contracts on their own accounts. Currently, only noncore customers may purchase gas and transport it for their their own needs. According to Indicated Producers, competitors should be permitted to offer the same full service package as the utilities. It suggests that brokers' access need not interfere with any end use priority scheme. We are interested in considering Indicated Producers' suggestion. At this time, however, it raises questions which have not been addressed by the parties to this proceeding, for example, relative liabilities between brokers, customers, and the utilities. We will address Indicated Producers' request when we review proposed capacity brokering programs in R.88-08-018.

The rules we ultimately adopt in this proceeding should improve circumstances which have limited access to competitive gas markets. As several parties point out, however, the smooth operation of the market requires that we implement capacity brokering. We again affirm our commitment to that goal and expect to develop capacity brokering as soon as possible after the final rules are issued in this proceedings.

C. Treatment of UEG Departments of Combined Utilities

The OIR proposes that UEG departments of combined utilities would be required to set up purchasing departments separate from the core gas purchasing department. UEG departments' gas purchases from core subscription services would be limited to 25 to 50% of total demand. The UEG would otherwise be treated like any other noncore customer. In setting forth this proposal, we expressed particular concern about how to implement this policy through a transition period.

We proposed limiting UEG access to core services because of a perception that combined utilities might be able to use their control over the operations of their systems to favor their electric departments. This circumstance would undermine competition. We noted our ongoing concern for UEG service obligations and increasing pressures on them to burn natural gas to improve air quality.

1. Positions of the Parties

a. The Settlement

The Settlement provides that the electric department of a combined utility would be treated as if it were unaffiliated with its gas department. It would be able to purchase gas from the gas department as any other customer.

b. PG&E

PG&E proposes to create a separate gas portfolio to serve a portion of its UEG requirements. UEG purchases from the core subscription service would be set by PG&E and the rest of the UEG requirements would be met through the separate portfolio. PG&E believes this is a reasonable compromise from the existing practice which PG&E believes provides benefits to both gas and electric customers.

PG&E believes limiting its UEG's access to core subscription will mean higher electric costs because the UEG will have to increase its reliance on more expensive gas supplies from the Southwest and may require expensive additional storage cycling capability to meet load swings. PG&E reminds the Commission that higher UEG costs will lead to higher northwest economy energy prices, QF energy prices and geothermal steam rates.

c. SoCal

SoCal comments that it is not directly affected by this issue because it is not a combined utility.

d. DRA

DRA argues that UEG gas demand is so large that its procurement decision can have a disproportionate effect on the entire market. DRA recommends the Commission impose the core subscription rules on all UEGs, not just the electric departments of combined utilities. It proposes that UEGs be permitted to purchase no more than 25% of the previous five years' annual average gas usage. DRA also agrees with the OIR's proposal to separate the electric department's procurement operations from those of the gas department's procurement operations.

DRA is not convinced, as are some parties, that PG&E's UEG demand keeps Canadian gas prices low. DRA points to information it obtained showing that Sierra Pacific Power Company paid an average of $1.11 per decatherm during a period when PG&E paid $1.90 per decatherm for Canadian gas.

e. CEC

CEC supports the OIR's approach toward UEG purchases from the core portfolio is a reasonable compromise considering the real or perceived undue influence over utility decision-making by UEGs.

f. Industrial Customers

UEG departments, according to CIG, should be treated like any other noncore customer, as set forth in the Settlement. CIG does not believe PG&E's electric department should be able to enjoy the advantages of PG&E's purchasing strategics which limits access by other customers of PGT capacity. CIG doubts that electric service reliability or cost will be compromised by the change in policy set forth in the Settlement.

g. UEG and Wholesale Customers

SDG&E strongly opposes the proposed UEG rules, arguing that they are designed to address problems that do not exist in it territory. Noncore customers, according to SDG&E, have not been denied access to gas because of SDG&E's service to its power plants. Like PG&E, SDG&E believes the new rules would increase administrative and economic benefits from the "synergies" of purchasing gas for core and UEG customers. SDG&E also comments that splitting utility purchases between core and UEG will increase the number of buyers which tends to raise prices not lower them. Rather than discriminate against UEG operations, SDG&E argues that the Commission should adopt policies aimed at the capacity constraints blocking access to Canadian gas. Southwest comments that UEGs will have market power whether or not they are permitted to purchase core gas from their associated gas departments, and that the proposed rule is likely to increase procurement costs for the customer base "left behind."

Edison opposes the OIR on the subject of UEG procurement on the grounds that the proposed restrictions will eliminate system efficiencies.

h. Pipeline Companies

El Paso believes UEGs of combined utilities should be limited in their purchases of core service to the least amount possible, perhaps 5-10% of total requirements. El Paso argues UEG customers are large, sophisticated users who should be required to purchase their needs on a competitive basis.

i. Independent Producers and Marketers

Salmon/Mock supports the Commission's proposal to limit UEG customers access to utility procurement services. As a core-elect customer, PG&E's UEG department has, according to Salmon/Mock, made firm pipeline capacity from Canada unavailable to noncore customers. Salmon/Mock propose no more than 10% of UEG load should be offered core subscription service. Salmon/Mock agree that reducing UEG access to core subscription may, in PG&E's case, expose PG&E to take-or-pay liability under agreements with A&S. Salmon/Mock suggest that renegotiation may be possible with some buy out penalties and that a buy/sell arrangement may mitigate negative effects of new rules.

Indicated Producers believe UEGs do not need to purchase any core services from its associated gas department, arguing that combined utilities have engaged in discriminatory behavior under existing rules. Recognizing that it may be difficult to phase out UEG core purchasing without notice, Indicated Producers suggests combined utilities be given at least six months to phase out purchases. If long term contracts have not by that time been renegotiated, the Commission should review the contracts to determine whether renegotiation is impossible and, if it is not, whether UEG core purchase amounts should be adjusted accordingly. UEGs, according to Indicated Producers, should be able to purchase gas from utility marketing affiliates like any other customer.

GasMark believes the OIR's treatment of UEG gas purchases would help preclude the use of the UEG function as a "dumping ground" for excess gas from the single portfolio and may improve UEGs' opportunities for purchasing less expensive gas supplies.

Hadson suggests the Commission consider limiting UEG purchases from utility marketing affiliates by permitting an allowable range whereby the more the UEG purchases from the utility, the less it can purchase from a utility marketing affiliate.

Enron recommends that UEG customers be treated like any other large customer. If a UEG's choice to subscribe to core service unduly restricts access to capacity, that issue should be addressed through capacity allocation rules.

NGC believes the Commission should move cautiously in changing the status of UEG departments. It suggests this issue may be better considered as a "second generation" issue to be resolved after rules are implemented and some experience is gained.

Capitol supports separating UEG gas purchasing departments from the core gas procurement departments of combined utilities, stating that the separation will enable the market to reallocated substantial transportation capacity promoting more competition.

Bonus objects to UEGs of combined utilities participating in any core portfolio because the UEG would then be provided preferential access to interstate pipeline capacity. With that preference, according to Bonus, competition may be stifled. Bonus also opposes the Settlement's provision to limit the noncore customer Canadian procurement option to A&S suppliers, which will restrict competition.

CPG objects to the OIR's proposal to limit the amount of gas the UEGs may procure from the utilities on the basis that it may result in millions of dollars in take-or-pay liabilities for PG&E and that it will reduce service reliability to UEGs, which are obligated to serve core customers. CPG suggests the Commission hold hearings on the subject of the proportion of UEG load serving core customers, the effect of "arbitrary limitations" on UEG purchases from gas utilities, and the environmental impacts of curtailed access to firm supplies.

NCO believes the OIR's approach toward UEG gas purchases unfairly and unwisely penalizes PG&E for supplying reliable, inexpensive gas over PGT. NCO also questions the wisdom of limiting UEG gas purchases and thereby risking incurrence of new take-or-pay costs in renegotiating A&S contracts.

j. <u>TURN</u>

TURN supports the settlement as protecting the benefits provided by the UEG class in keeping utility procurement demand high. TURN is especially concerned that UEGs be permitted to purchase gas from the utilities in order to maintain California's relationship with Canadian producers. According to TURN, separate procurement activities of the gas and electric departments of a combined utility may have the effect of increasing gas costs for all customers, as one department works to outbid the other. TURN believes the duplication of staff and other resources would be costly.

TURN also comments that the core-elect transmission service proposed in the settlement will promote a more competitive procurement market by eliminating the gas utilities' monopoly over highly reliable gas supplies.

k. <u>Cogenerators</u>

CSC objects to UEGs being offered any core subscription services because they should not be permitted to "end-run" the end-use priority system for noncore customers by electing to take gas through the subscription core service.

l. <u>DGS</u>

DGS has no objection to permitting UEG customers to purchase up to 40% of its gas requirements from core subscription services.

2. Discussion

A major issue in this proceeding is the effect PG&E's UEG volumes have on Canadian gas prices. PG&E and TURN believe PG&E's purchases on behalf of its UEG may keep load high and provide PG&E with bargaining leverage in its negotiations with Canadian producers. More likely, however, PG&E's UEG loads dampen competition in ways which are costly to all ratepayers. Because PG&E buys gas through its affiliate, A&S, and passes along the costs of the gas to ratepayers, dollar for dollar, PG&E may not have an adequate incentive to bargain hard with producers. Contributing to this is PG&E's exclusive access to PGT, which arises in large part because of the service PG&E provides its UEG. It appears that Canadian suppliers are not given equal opportunities to negotiate sales agreements and seek access to the California market. DRA supports this view in arguing that PG&E is paying much more than the market price for Canadian supplies.

This problem is unique to PG&E. Other of the state's UEGs are noncore customers. There is no evidence to suggest at this time that core subscription by UEG customers other than PG&E's electric department would result in the monopolization of access to a regional supply source by a single utility. On the other hand, we see no reason to limit any policy to PG&E. Circumstances could change in ways which would permit the kind of problems which exist in PG&E's territory.

We will propose that the electric departments of combined utilities be prohibited from subscribing to the core for more than 15% of their average annual requirements over the previous three years. The UEG, however, may use pipeline capacity according to the rules for allocation of interstate and intrastate capacity.

We recognize that some duplication of effort may occur because PG&E's electric department must create its own procurement operation. This loss of efficiency, however, is likely to be more than offset by increased market efficiency resulting from related elements of the program we propose today.

We propose the following rule for UEG gas purchases:

> Electric departments of combined utilities may purchase from their gas departments' core subscription service up to 15% of the electric department's average annual requirements over the preceding three years. The UEG may purchase transportation as any other noncore customer.

D. Balancing and Standby Services

The OIR recognized that some type of balancing and standby services would continue to be needed for noncore customers because variations will always occur between what a customer nominates and what arrives at the California border. We proposed rules which are similar to those proposed to the FERC.

We proposed that negative and positive imbalances up to the lower of 5% of customer nominations or 30,000 Dthms/month may be carried forward without charge provided they are made up within 45 days of notification. Negative imbalances in excess of the limits would be considered standby service. When standby service is available, the rate for gas would be the cost of incremental gas supplies plus 10%. For positive imbalances, the utility would purchase all deliveries in excess of the lower limits over a customer's nominations at a rate equal to 95% of the WACOG.

1. Positions of the Parties

a. The Settlement

The Settlement would allow transportation customers to be out-of-balance by as much as 20% in either positive or negative direction without incurring any additional charges. If the sum of past months' and current months' imbalance exceed 20% of the current month's consumption, then imbalance charges would be applied to the excess. The amount that did not exceed the 20% tolerance would be carried over for inclusion in the subsequent month's calculation as a running total. The Settlement does not include a notice provision. It does, however, allow customers to trade positive and negative imbalances which would be credited by the utility before the end of the billing period, thereby allowing the customer to avoid imbalance charges.

b. PG&E

PG&E makes its comments on the topics of balancing and standby service in consideration of its view that its operating flexibility is very limited, arguing in favor of discouraging imbalances and use by customers of standby services.

PG&E believes the 30,000 Dth per month limit is punitive to very large customers. It proposes that all customers have the same relative quantity of balancing service. On the subject of standby charges, PG&E believes the OIR does not go far enough to discourage the use of standby service because the proposed rate could make standby service less expensive than core supplies. PG&E proposes a standby rate of 200% of the cost of the core portfolio, a rate approved by the FERC for imbalance charges for El Paso. Similarly, PG&E proposes a less attractive purchase price for positive imbalances, a rate which would be equal to 50% of the core WACOG.

PG&E also comments that standby service should be curtailed before any P-5 customers. For customers who continue to take gas after they have been notified that no standby service is available, PG&E proposes a penalty in the amount of $10 per Dth, consistent with the Northwest Pipeline Corporation's rate for unauthorized imbalances. PG&E does not propose any additional penalty at this time for customers who are habitual users of standby service.

PG&E recommends that all balancing and standby service revenues be credited to the core purchased gas account (CPGA).

c. <u>SoCal</u>

SoCal explains the guiding principle behind the Settlement provisions for balancing is that customers should be afforded imbalance coverage without extra charge to the greatest extent possible as a way of making transportation service convenient to customers.

SoCal defends the 20% tolerance level in the Settlement on the basis that most customers stayed within that tolerance during 1989 and many large customers were outside the 5% level proposed by the OIR. SoCal does not support the notice requirement in the OIR, believing it would promote dispute and costly administration.

SoCal believes the Commission's 5% tolerance is unrealistic because it assumes that customers could readily be in perfect balance within a 45-day period. Because all imbalances would need to be perfected and because of the near impossibility of attaining perfect balances, the gas utility would have to bill every transportation customer every 45 days.

SoCal suggests that if the Commission adopts its own balancing rules, it should require customers to get back within tolerances within 45 days, rather than back to a perfect balance. SoCal states tolerances should be a percentage of consumption, not nominations to avoid gaming nominations.

Like other commenters, SoCal believes the OIR's proposal on purchasing positive balances might result in utility purchases priced higher than available discretionary supplies. SoCal supports the Settlement's provision setting the payment at 80% of the lowest incremental cost of gas in the portfolio.

Regarding stand-by charges, SoCal supports the Settlement's approach of rates set at the higher of the highest-priced discretionary supply in the utility portfolio or the WACOG of the portfolio. SoCal states it prefers this approach because the incremental cost of gas could be lower than the WACOG. To assure the standby rate is no lower than the charge for scheduled procurement service, the Settlement adds a one cent per therm fee to the utility WACOG. Because standby service requires use of storage and other facilities, the Settlement adds a 1.8 cents per therm charge to the volumetric standby rate, subject to revision in each utility's ACAP.

d. DRA

DRA believes that utilities should be under no obligation to purchase positive imbalances. DRA comments that the Commission's proposal could result in higher gas costs for core customers when the cost of incremental supplies is less than 95% of the system average cost. According to DRA, if the customer does not offer its excess gas at a price that is beneficial to core customers, it should pay an imbalance penalty until the customer's supplies are once again balanced. DRA recommends the penalty be 10% of the incremental cost of gas.

DRA recommends a 10% threshold for imbalances, the amount permitted on the interstate system, is a reasonable limitation. It also believes that 30 days rather than 45 days is an appropriate time period for carrying forward balances.

With regard to standby service, DRA believes the Commission's proposal offers too much of a concession to customers and marketers. It recommends that the rate for standby service should be the cost of the most expensive supply of gas in the portfolio plus an imbalance surcharge. DRA would promote a system which discourages the use of standby service.

e. CEC

The CEC supports the OIR's approach regarding balancing and standby services.

f. UEG and Wholesale Customers

SDG&E asserts the OIR's treatment of balancing and standby service is too restrictive and suggests a tolerance of 10%, made up on a monthly basis. Penalties over and above standby service are unnecessary, according to SDG&E.

Edison asks the Commission to recognize in its final rules the public utility obligation of electric utilities by providing the means for electric utilities to meet the variable energy demands of their customers. The 5% tolerance proposed in the OIR, according to Edison, does not recognize the operational constraints it faces in procuring gas supplies. For example, Edison does not have access to firm capacity rights or firm storage. Edison recommends a 20% tolerance and the elimination of the 30,000 Dthms/month tolerance.

Edison proposes several rules for balancing including a 60-day make-up period, trading between customers with positive and negative balances, and forgiveness for imbalances which occur because of bumping trimming or curtailment.

Edison also objects to using the existing end-use priority classification to allocate standby service because it would result in Edison having the lowest priority among noncore customers for standby gas.

City of Palo Alto argues in favor of a 20% balancing tolerance on a monthly basis. It also believes no party should be forced to be a supplier of last resort and that standby services should be priced to recover costs and not to penalize customers.

SCUPP recommends the balancing and standby provisions of the Settlement, arguing that the OIR proposals are too restrictive.

Southwest concurs in the Commission's balancing and standby service provisions. It believes, however, that the buyback of positive imbalances should be the lower of the original noncore contract price or 95% of the system average cost of gas, in order to discourage customers from incurring positive balances.

g. <u>Independent Gas Producers and Marketers</u>

Salmon/Mock proposes that gas utilities should not be permitted to offer standby service in that the service would make them participants in the noncore procurement market. A better alternative, according to Salmon/Mock, is to require customers to contract with third-party suppliers for standby supplies. If standby providers fail to deliver, and customers continue to take gas, penalties should be imposed.

Salmon/Mock believes balancing tolerances should be increased from 5% to 20%, and that with these wider limits the 45-day period to clear imbalances is reasonable.

Enron agrees that balancing is needed but that it should be discouraged and designed so that customers cannot "game" the system.

CPG suggests the Commission consider the effect of the OIR on coordinating interstate and intrastate nominations, receipts, deliveries and transportation rights. CPG suggests with more firms entering the market, as the OIR would promote, this coordination effort may become more difficult, thereby reducing the amount of available capacity.

Indicated Producers suggests the proposed balancing rules are too restrictive, suggesting elimination of the volume cap on tolerance as discriminating against large customers, and increasing the percentage tolerance to 20% of daily quantities. A 45-day make-up period is reasonable, according to Indicated Producers. Negative imbalances which are not made up should be subject to standby service rates at the WACOG plus 20%. Positive imbalances should be sold to the utility at 80% of the WACOG, an amount lower than proposed by the OIR, which Indicated Producers believes is not low enough to discourage positive imbalances.

Hadson suggests the Commission consider allowing shippers to carry as "banked" supply a quantity equal to 20 times the maximum daily contract quantity. This approach has, according to Hadson, been successfully implemented this practice in its open access program for years.

GasMark supports the provisions of Settlement generally, arguing that the OIR approach is too restrictive.

Capitol believes a 10% tolerance is more reasonable than the 5% or 30,000 Dthms/month.

McFarland, a Texas based gas producer, urges the Commission to consider in this proceeding the use of private storage as an alternative to utility balancing, standby, and storage services. McFarland states that private storage is not economically viable now because the costs of utility storage and balancing are bundled with transmission rates. Such services would, according to McFarland, further the Commission's objectives first set forth in I.87-03-036 issued to address storage matters.

h. Industrial Customers

CIG objects to the balancing requirements proposed in the OIR, stating that customers cannot balance their takes without any tolerance within the 45-day period. CIG supports the Settlement's balancing provisions, which provide more flexibility for noncore customers without imposing burdens on the utility or other customer classes.

Shell recommends that imbalances up to 15-20% be allowed and that makeup periods for these imbalances be at least on a quarterly basis.

Carlton supports the OIR's pricing of gas purchases resulting from positive imbalances but objects to penalties for standby service. It comments that its own gas use may vary 40% from month to month.

Philip Morris argues that tolerance levels for imbalances are appropriately 20% of monthly nominations. Imbalances should, according to Philip Morris, be subject to a make-up period of 60 days after notification.

i. Cogenerators

CSC recommends the Commission adopt the balancing tolerances and make-up periods proposed by the Settlement. CSC believes the OIR's proposed purchase price for positive imbalances is too high to discourage over-nominations, suggesting the purchase price be set at 75% of the WACOG. Likewise, it suggests a tougher stand on negative imbalances, suggesting a standby rate of the WACOG plus 10% in the summer and 25% in the winter. CSC objects to customers trading imbalances as proposed by the Settlement, arguing that the provision provides inadequate incentives to balance supplies to the harm of customers who do not over-nominate supplies.

AES argues the OIR's approach to balancing is an overreaction to the current capacity constraints. It believes the tolerance levels and the penalties are not workable and will result in windfalls to SoCal. It supports the proposal set forth by CSC.

j. <u>Pipeline Companies</u>

Transwestern believes that if standby services are priced to reflect costs, the Commission's concerns over subsidies from the core and improper incentives to noncore customers to use standby services are mitigated. Transwestern recommends a portion of gas storage costs should be included in the standby charge because the utilities must rely on storage to provide standby service.

2. <u>Discussion</u>

As PG&E and DRA suggest, we wish to discourage balancing and standby services because these services complicate utility operations and planning. We concur with the comments of the parties, however, that the 5% window may be too restrictive. We will propose a balancing tolerance of 10% of nominations with 30 days for carrying forward the balance. To clarify our intent, customers must be within the 10% tolerance to avoid charges; they need not be in perfect balance at any time. We also agree with the parties that a tolerance based on a fixed gas quantity is too restrictive and may be punitive to very large customers. We will therefore eliminate reference to a fixed quantity in our proposed rules.

Trading of imbalances, as the Settlement proposes, should also be permitted. Trading will ease the effect of the restrictions on balancing. The utilities, however, should be indifferent to trading from an operational standpoint.

Although we propose to ease the tolerance level and allow trading, the comments of several parties convince us that the prices proposed by the OIR for purchases of overnominations and standby services are not restrictive enough. We propose a standby service rate equal to 150% of the core WACOG. Utility purchases of overnominations should be set at 50% of the core WACOG. We believe these price levels will protect core customers from increased liabilities and encourage noncore customers to plan carefully nominations carefully. Standby service, as several parties suggest, should have the lowest priority during periods of curtailment.

Our proposed rules for standby service and balancing service are as follows:

> The utilities shall provide balancing services to noncore customers. The tolerance for balancing services shall be 10% of customer nominations. Customers shall have 30 days from the date of utility notification to reconcile balances. Noncore customers may trade imbalances to avoid liability.
>
> Where positive imbalances fall outside the 10% tolerance for more than 30 days after utility notification, utilities shall purchase noncore customers' overnominations at a rate equal to 50% of the core WACOG.
>
> Where negative imbalances fall outside the 10% tolerance for more than 30 days after utility notification, utilities shall provide standby services to noncore customers. Standby service gas rates shall be equal to 150% of the core WACOG. Standby service shall have the lowest priority during periods of curtailment.

E. Excess Gas Supplies

The OIR proposes that utility marketing of excess core gas supplies to noncore customers be prohibited. We expressed concern that the utilities' ability to market excess supplies might undermine our objective of eliminating utility participation in the noncore procurement market.

1. Positions of the Parties

a. The Settlement

The Settlement permits sales of excess gas to off-system customers under certain conditions. The utility would be required to conduct a blind bidding process and to sell the gas to the highest bidder. The utility would not be permitted to use its capacity rights to transport excess gas sold off-system. Excess gas sales could only be made when necessary to avoid gas inventory or similar charges.

b. PG&E

PG&E argues that a total ban on marketing excess supplies is impractical because PG&E's system is not flexible enough to assume that portfolio risk management strategies will be sufficient or that PG&E can simply inject excess core supplies into storage. A total ban would force PG&E to increase the proportion of spot supplies in its core portfolio and require it to increase its storage injection and cycling capability. As an alternative to the OIR's approach, PG&E recommends that it be permitted to sell excess core supplies to other utilities. This approach will permit some system flexibility while still effectively eliminating PG&E's participation in the noncore gas markets.

c. SoCal

SoCal supports the Settlement provisions on the grounds that it might be in a position where it would be more economically advantageous to take gas and resell it at the highest available price than to incur the cost of turning the gas back under the contract. For unspecified legal reasons, SoCal states it might wish to use an affiliated marketing company to sell excess supplies and should not be prohibited from doing so.

d. UEG and Wholesale Customers

SDG&E objects to a prohibition of sales of excess gas. SDG&E believes the Settlement's provisions on this subject are reasonable.

Southwest believes the prohibition proposed in the OIR will force gas utilities to rely too much on spot purchases reducing system reliability. Southwest believes sales of excess gas alleviate take-or-pay obligations and prevent needless disruptions in providing services to noncore customers.

Edison supports sales of excess core gas as long as noncore customers are not forced to buy gas and appropriate monitoring ensures that the gas utility does not take unfair advantage of pipeline or storage rights in order to make these sales.

e. DRA

DRA believes utility shareholders should be responsible for the costs of gas which are in excess of procurement customer requirements. This rule, according to DRA would encourage flexible and robust procurement practices that take into account future uncertainty and would discourage the take-or-pay problems of the 1980s. DRA also proposes that utilities should not be permitted to sell excess gas supplies to noncore customers.

f. CEC

CEC supports the OIR proposal to prohibit the marketing of excess core gas to noncore customers. The CEC comments, however, that making shareholders responsible for excess core gas costs may force the utilities to rely too much on spot gas. The CEC also believes this penalty is unreasonable because temporary excess gas supplies may sometimes in the best interests of core customers.

g. Independent Producers and Marketers

Salmon/Mock agree with the OIR's proposed ban on sales of excess supplies and believes the Commission should extend the prohibition to off system sales.

Phillips supports the OIR's proposal to ban excess gas sales.

Enron argues that the utilities's core purchases should be made to match their core demand, just as noncore customers procuring their own supplies will be expected to do.

CPG suggests that the OIR's limitations on sales of excess gas will be expensive for gas ratepayers because of the reduced flexibility it would impose. Such flexibility is required because of the extreme load swings which occur in serving the core market.

GasMark supports the proposed prohibition on sales of excess gas, arguing that it may prevent a situation which occurred last year when one utility curtailed inexpensive gas supplies of noncore customers in favor of its own more expensive purchases.

Hadson supports the OIR's proposed prohibition on sales of excess core gas.

Capitol supports the OIR's limitations on sales of excess core gas to the noncore.

h. Industrial Customers

CIG supports the settlement will permit excess core sales if necessary to avoid the incurrence of reservation fees, inventory charges or take-or-pay penalties.

2. Discussion

In R.90-02-008, we proposed to prohibit utilities from selling excess gas supplies because such sales may promote utility participation in the noncore market. In this decision, we seek to protect competition in noncore gas markets by proposing to eliminate the noncore portfolio and place new conditions on core services to noncore customers. Today's decision also prohibits the utilities from setting up new noncore marketing affiliates.

Notwithstanding our view that utilities should generally limit their gas procurement activities to the core, we have reconsidered our view regarding sales of excess core gas. There may be circumstances where the utilities would incur contract penalties or take-or-pay charges which would arise when core demand is substantially lower than expected. In those cases, core customers are better off if the utilities sell the excess gas to noncore customers. We propose to permit the utilities to sell excess gas under the guidelines set forth by the Settlement. That is, the utilities would conduct a blind bidding process and would not be permitted to use capacity rights to transport excess gas sold off-system. The sale may only be made to avoid extraordinary charges. The utilities may not, as SoCal suggests, sell the gas through affiliates because we wish to avoid the auditing problems that arise with affiliated transactions. The utilities may not sell excess gas simply to avoid storing it and may not use its pipeline or storage rights to make the sales.

Our proposed rule for the sale of excess gas is as follows:

> The utilities shall sell excess 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.

III. Incentives

R.90-02-008 proposed several possible regulatory incentives for assuring efficient and prudent utility management. We also expressed our concern with conservation, commenting that we hoped to promote the use of gas relative to other, less clean fuels, but that conservation of all fuels is a primary objective. Currently, core gas costs are included in balancing accounts and reviewed in annual reasonableness reviews. We review non-fuel costs in general rate cases which the gas utilities file every three years. R.90-02-008 sought comments on several other possible regulatory mechanisms:

> Annual Gas Rate: The AGR as we described it would operate like the Annual Energy Rate (AER) for electric utilities whereby the gas utility would be at risk for some portion of the forecasted revenue requirement for gas purchases during the year.
>
> Indexed Gas Costs: The indexed gas rate (IGR) would index a percentage or quantity of gas costs to a more general index, for example, national gas costs. If the utility's gas costs are higher than the indexed rate, it would forfeit the difference. Conversely, the utility would earn revenues when its gas costs were below the IGR.
>
> Multi-year ACAPs: We asked for comments on extending the period between ACAPs. We proposed that annual gas cost reviews may not provide enough time for the utility to realize the benefits of increased throughput.
>
> Base Rate Indexing: The BRI would be used adjust rates for nongas costs just as the IGR is used for adjusting gas costs.
>
> Risk Sharing Mechanisms: We asked the parties to comment on the appropriateness of such mechanisms as the NRSA account, which provided a band around revenues for which the utilities were at risk.

1. Positions of the Parties

a. Settlement

The Settlement does not address incentives except that it would implement full balancing account treatment for noncore transmission costs and revenues. Accordingly, it would reinstitute a supply adjustment mechanism (SAM) whereby the utilities would be reimbursed for losses which occur because demand is less than forecasted.

b. PG&E

PG&E generally suggests retaining the existing set of regulatory conventions and supports the continuation of reasonableness reviews. It would extend balancing account treatment to noncore transportation revenues. Although PG&E opposes any type of indexing mechanism for core revenues, it comments the least objectionable alternative to reasonableness reviews would be a gas indexing mechanism like the IGR.

c. SoCal

SoCal comments the existing regulatory framework provides ample incentives for gas utilities to keep their costs down. It believes low costs should not be the only goals of regulation and that safety, conservation, and service quality must be considered.

SoCal argues the AGR and IGR concepts present difficult implementation problems and raise questions of fairness. Increasing the period between ACAPs, according to SoCal, will not provide any opportunity for the utility to improve earnings, although it may exaggerate losses because SoCal's the demands on SoCal's system are greater than its ability to provide service.

SoCal proposes balancing account treatment for all noncore market revenues as a way to promote conservation objective. Until then, SoCal believes the NRSA mechanism should be in place for all noncore revenues not subject to balancing account treatment proposed in the settlement. SoCal recommends that the Commission hold workshops and later initiate an investigation if it intends to seriously consider incentive mechanisms.

d. DRA

DRA strongly opposes the application of any new balancing accounts, arguing that an ever more competitive noncore market disstates that the utilities bear their share of risk. DRA also argues that capacity constraints do not increase utility risks with regard to ACAP forecasts: because the ACAP forecast includes a forecasted curtailment level, there is an equally likely chance of the forecast being either too high or too low.

If the Commission retains the NRSA account, DRA recommends the Commission extend the period between ACAPs to two years. DRA believes the disadvantages associated with IGRs and AGRs outweigh the advantages. DRA comments that promoting gas use does not necessarily conflict with conservation goals, rather, it encourages burning gas as an alternative to fuel oil. Accordingly, no additional balancing accounts are needed.

e. <u>TURN</u>

TURN opposes the AGR because it would create more controversy in forecasting. Applying an IGR would avoid this controversy once the index was created. TURN believes the IGR should tie recovery to percentage changes in the established index, not absolute price levels. In so doing, TURN believes there will be reduced pressure to establish a perfect index. Initially, TURN suggests 20% of core gas be subject to the index, the remainder retaining existing balancing account treatment.

TURN also comments that noncore nongas costs should not be given balancing account treatment. It argues that base rate indexing is not a good idea for gas utilities because their investments are "lumpy."

TURN supports elimination of the NRSA and multi-year ACAPs. It suggests two-year ACAP with the goal of eventually folding the ACAP issues back into the gas utilities' general rate cases.

f. <u>NRDC</u>

NRDC, a non-profit environmental advocacy organization, strongly supports balancing account mechanisms which would remove incentives for utilities to promote gas use. NRDC supports any efforts to promote gas conservation and comments that higher gas use will not necessarily result in displacement of dirtier fuels.

g. <u>Industrial Customers</u>

CIG believes an AGR is nonsensical because, according to CIG, there is no relationship between utility behavior and performance in gas purchases. The IGR might be a self-fulfilling prophecy because of the effects of utility purchases on the price of gas in California. CIG supports elimination of NRSA, scheduled to take place May 1, 1990 and a multi-year ACAP because it believes the utilities are able to control, to some extent, their nongas costs.

h. <u>UEG and Wholesale Customers</u>

SDG&E opposes an AGR but believes core procurement costs could be measured against a market index like the IGR. SDG&E argues in favor of the existing regulatory program which has eliminated balancing accounts and permitted discounting transportation rates.

Edison opposes changes to regulatory programs for gas utilities, asserting that multi-year ACAPs will impose too much risk on the utilities.

SCUPP supports elimination of the NRSA but suggests retaining other elements of the Commission's regulatory program, including the annual ACAP.

Generally, Southwest does not support any changes to the existing system. It opposes application of an IGR or AGR because of the difficulty of fairly and accurately implementing them. Southwest believes multi-year ACAPs may reduce regulatory expenses but argues against any risk sharing mechanisms. It also suggests the Commission adopt uniform guidelines for acceptable procurement practices.

Long Beach supports less frequent offset proceedings and suggests unbundling core rates into gas costs and nongas costs as a means of eliminating undercollections in balancing accounts.

i. <u>CEC</u>

The CEC does not support the AGR or an indexed gas rate. CEC believes conservation efforts are served by unbundling and comments that increasing gas use as an alternative to oil use does not necessarily conflict with conservation objectives.

j. <u>DGS</u>

DGS suggests the existing regulatory mechanisms for reviewing nongas costs are adequate if the Commission would be more diligent in its oversight. DGS suggests reinstituting supply adjustment mechanisms, as put forth in the settlement, to improve conservation efforts.

k. <u>Gas Producers and Marketers</u>

CPG believes regulatory incentives are likely to do little to change the market or enable the utilities to control and, therefore, cannot be expected to achieve significant savings for the core. CPG opposes the AGR on the grounds that it is inconsistent with the Commission's assumption that the gas market is workably competitive. An AGR, according to CPG, would interfere with the existing contract between A&S and PG&E and may have a discriminatory effect on Canadian imports. CPG also opposes the IGR.

Salmon/Mock opposes the AGR because of the difficulty of forecasting. It also opposes the IGR mainly because the size of the California market will be a significant component of the index used to justify utility costs. National gas costs, according to Salmon/Mock, are not ideally tuned to west coast gas market conditions. Salmon/Mock opposes use of balancing accounts. Salmon/Mock believes one reasonable incentive would be to hold the utility liable for some portion of gas costs which fall outside a band of, for example, 20% of the average spot price. Salmon/Mock recommends no changes to regulation of nongas costs.

Capitol believes it is premature to consider incentives at this time. NCO believes an AGR would encourage the utilities to focus too much on the short-term minimization of gas costs.

GasMark supports a mechanism whereby shareholders would be rewarded for prudent purchasing and penalized for poor purchasing decisions.

2. Discussion

Although the parties presented relatively little analysis of the incentive portions of the OIR, we believe we have learned enough from the responses and from our regulation of other industries to take further steps in our review of gas utility incentives. We are interested in exploring further the possibility of indexing nongas costs and core and core subscription gas costs. In combination with indexing, we propose to adopt balancing account treatment for noncore gas transmission revenues and to remove the utilities' authority to discount noncore transmission rates.

These next steps result from our strong interest in putting the gas utilities at risk for costs that are under management control. Regulatory incentives should be stable, understandable, balance risk and reward, and provide a long-run incentive to improve efficiency. Indexing may provide such incentives for gas and nongas costs.

At the same time, when costs or sales fluctuate widely, out of managements' control, and when a utility service is a monopoly service, we are interested in regulation that focuses management attention on costs and markets rather than Commission proceedings. We ask for parties' comments on the following proposals.

a. Nongas Costs

We seek to explore further whether to apply the incentive ratemaking approach we adopted for Pacific Bell and GTE of California to the nongas costs of the gas utilities. The utilities raised potential problems with this approach. First, they raised concerns about safety programs. We have full confidence that the utilities will do what is needed to safeguard the public and their employees, and to comply with pertinent safety rules, no matter what regulatory framework is adopted. Moreover, we fail to see how indexing nongas costs differs from a more traditional ratemaking approach where safety is concerned because neither allows dollar-for-dollar recovery of safety expenses. We have not been apprised of any safety problems caused by the current regulatory program.

Second, gas utilities comment that they have "lumpy" investments that cannot be reflected in indexed rates. To the contrary, a major benefit of indexing is that it gives the utilities a clear incentive to make cost effective investments, because the utility keeps revenues which exceed costs. A lumpy investment should be as cost effective as a string of small investments.

Third, the utilities cited a lack of technological innovations which promote efficiency improvements, unlike the telecommunications companies which have saved money by installing digital switches and fiber optic cable. This is not a valid reason to oppose indexing. To the contrary, to the extent indexing improves management incentives it may also promote the development of cost-saving technologies.

There is at least one major difference between telecommunications and gas utilities. The sales of gas utilities can vary widely, depending on the weather, while phone usage is not weather sensitive. We indexed the <u>rates</u> of the two phone companies, but for gas utilities it makes sense to explore indexing their nongas <u>costs</u>. The formula that would be analogous to the phone companies' rate index would be: nongas costs in a future year for ratemaking purposes equals the prior year's costs, multiplied by one plus an index's change minus a productivity factor, plus or minus special "Z" factors. The "Z" factor would permit recovery of substantial cost increases or decreases resulting from factors out of the utility's control, such as major changes to tax laws. The indexing of nongas costs, if adopted, would replace general rate cases and financial and operational attrition proceedings. The indexed costs would be allocated to various customer classes in ACAPs.

We are not adopting nongas cost indexing at this time. We want to explore this approach in more detail in order to determine whether to hold evidentiary hearings on the issue. Therefore we ask the parties to respond to several questions regarding nongas cost indexing.

> What costs should be indexed? Rate case costs? Interstate pipeline demand charges and transition costs? Other categories?
>
> What index representing inflation is the best candidate?
>
> What productivity factor should be selected? How can this be determined?
>
> What cost changes should be included as "Z" factors?
>
> Should there be sharing of returns above a specified level between shareholders and ratepayers? Should there be ceilings or floors, or triggers for review, on the rates of return?
>
> Should the index and productivity factor be reviewed at periodic intervals? Changed?

After considering the parties' recommendations, we will decide whether to pursue the approach in more detail. We will adopt nongas indexing if it appears to provide benefits for ratepayers by guaranteeing productivity levels and for shareholders by enhancing opportunities for earnings from efficiency improvements.

b. Core Gas Procurement

We also want to explore indexing gas costs for core and core subscription customers. The parties were clear and persuasive in recommending against an AGR but some were cautiously supportive of a longer term IGR, actually an index for gas costs. We are interested in pursuing further TURN's suggestion of indexing part of the utilities' core gas costs with an index derived from changes in regional gas costs. TURN illustrated the suggestion with an example. If the Commission were to index 20% of PG&E or SoCalGas' core gas costs, that would represent about $200 million. If actual gas costs turned out be be 10% higher or lower than the change in the index, that would represent an incentive of $20 million, which is within the risk range of the Annual Energy Rate and the now expired Negotiated Revenue Stability Account.

PG&E stated such an approach would be the least objectionable of new approaches if it were to replace reasonableness reviews. We agree that an indexed gas cost (IGC) could replace reasonableness reviews which are highly adversarial and require considerable speculation.

If the Commission were to adopt this approach, PG&E prefers an index that is specific to each utility's gas markets, is changed frequently, and is capped in its impact on each utility. The problems raised by other parties persuade us that developing an IGC would not be an easy undertaking because of the difficulty of selecting an index reasonably representative of core gas costs. If the index were broad, based for example on the change in the average North American gas price, regional weather effects could make it vary widely from California conditions. But if an index were specific to California gas purchasing markets, it would be substantially under the utilities' control and would act like a balancing account. Thus the selection of an appropriate, moderately representative index clearly is a difficult challenge.

Parties also made us mindful that the utilities might be able to "game" any index selected by the Commission. Gas buyers and sellers would know the index, and the utilities might index the price of their gas purchases to the Commission-selected index. They could forego earnings opportunities in return for limiting risks.

A third problem raised by the utilities is that indexing would give them a disincentive to buy gas when its price peaks in cold weather, even though the gas may be needed for reliability. Accordingly, they argue in favor of maintaining full balancing accounts to continue to give them the flexibility to buy gas whenever it is required for reliable service.

These problems in indexing some core gas costs appear to be serious but not insurmountable. The test of the IGC's usefulness will be whether it is preferable to reasonableness reviews, which we would abandon if we could develop a more straightforward incentive to keeping gas costs down.

We are interested in exploring the TURN approach because we would prefer a balanced incentive that would reward shareholders when utility management is able to lower core gas costs and perform well, and penalize them when costs get out of line, in place of full balancing account treatment and reasonableness reviews. We do not know whether that is desirable, so we ask for the parties to respond to several questions regarding gas indexing.

> What would be a reasonable and representative index?
>
> To what percent of core and core subscription gas costs should the index apply?
>
> For what period of time should the index apply? How often should it be reviewed?

> Is an IGC preferable to reasonableness reviews in terms of providing proper incentives, and accurate and simple measures of sound procurement practices?

As with exploring indexing nongas costs, we are interested in each party's optimum approach, assuming the Commission were to adopt core gas cost indexing. We will use these approaches to determine whether to commit to an indexing approach, or to retain the current 100% balancing account and reasonableness review framework.

Parties should also present advantages and disadvanatages they foresee in adopting indexing over the current situation. There may be a diminished need for an indexing incentive approach if the gas procurement markets continue to become more transparent on prices, with buyers and sellers agreeing only to short-term price commitments. Reasonableness reviews might be straightforward under such circumstances. But the utilities will continue to need to make important decisions about length of contracts, take-or-pay levels, firmness and other purchasing factors. We would prefer to put the risks of such decisions on utility management if efficiency improvements could be expected from an indexing incentive approach without major adverse effects.

c. Noncore Transmission

The Commission placed the utilities at risk for noncore transmission revenues in order to provide an incentive to promote the use of gas over other fuels, and lower nongas costs allocated to the noncore. Our impression is that this has not been a successful incentive. The utilities may be focusing on the risks associated with throughput forecasts in ACAPs rather than on marketing. Variations in noncore thruput, especially due to electricity demand, can be outside of the utilities' control, leaving management decisions vulnerable to chance.

We wish to consider whether firm and interruptible noncore transmission should be treated the same as core transmission, with balancing account treatment that allows the utilities to recover the adopted revenue requirement even with lower-than-expected demand. The utilities would still be at risk for transportation costs, and, if we index nongas costs, there would be an improved efficiency incentive for those costs that are under the utilities' control. But noncore throughput and revenues are too uncertain to operate as a marketing and cost incentive.

In addition, air pollution regulations are making it increasingly difficult for noncore customers to use alternate fuels. Many noncore customers are becoming increasingly captive customers of utility gas transmission. Further, we may want to encourage gas utility demand side management programs for noncore customers. Perhaps we should treat all noncore transmission as a monopoly service, reinstate balancing account treatment of revenues, and remove the provision which allows the utilities to discount noncore transmission rates. Buyers and sellers of noncore gas should know tariffed transmission rates and bargain between themselves accordingly. Eliminating the discounting will remove the gas utilities from negotiations between buyers and sellers of noncore gas.

With this treatment, the ACAPs should become simpler and much less controversial. With the contention over noncore revenue and throughput forecasts mitigated, the period between ACAPs could be extended to two or three years, perhaps with a trigger mechanism to true up balancing accounts. Alternatively, we could true up balancing accounts annually, but extend the period between cost allocation decisions. We invite parties to comment on the desirability of these possibilities.

We will consider how to proceed on the incentives issues in a future decision. Parties will have 60 days to respond to the questions we raise on incentives. If we do proceed with indexing gas cots, we plan to hold evidentiary hearings on specific index and productivity factors.

IV. Implementation Schedule

R.90-02-008 stated we would issue proposed rules, ask for comments on the proposed rules, and then issue a final decision. We left open the question of how and when any regulatory changes might be implemented.

1. Positions of the Parties

a. The Settlement

The settlement anticipates the implementation of its provisions shortly after the Commission issues a decision contingent on the utilities using their existing interstate capacity rights on behalf of customers as an interim measure. The settlement proposes workshops to provide parties with details of the program. It also provides for reevaluation of the program three years from the date of its approval. If a settlement party seeks to make any program changes before the end of the thre- year period, it agrees to meet with other settlement parties to develop an mutually agreeable change.

b. PG&E

PG&E proposes final rules be adopted by the end of 1990. During Spring 1991, the utilities would implement core subscription, noncore access, firm-interruptible rates, balancing accounts, the UEG portfolio, and standby service. By the end of 1991, it would establish a capacity brokering program.

c. Gas Producers and Marketers

CPG urges the Commission to require that new procurement policies should apply only when existing commitments expire and with adequate notice. CPG also suggest numerous factual issues should be addressed prior to the implementation of certain rules proposed in the OIR. Most of the issues CPG raises relate to contractual obligations, UEG operations, and gas utility incentives.

d. DGS

DGS suggests implementing a new program no sooner than nine months after a final Commission order. If the Commission adopts the settlement, however, its provisions could be implemented in 120 days.

e. UEG and Wholesale Customers

Edison recommends the Commission implement the OIR provisions only after the capacity brokering and permanent storage programs have been put into place.

2. Discussion

The type of rules proposed in this decision could be implemented fairly soon, no later than Spring 1991, as PG&E suggests. The proposed rules would not require the introduction of capacity brokering because we provide an interim resolution for firm transportation needs.

PG&E and CPG list numerous issues which they believe should be resolved in hearings before the Commission takes any action. The issues they raise are certainly of interest, and yet we fail to see how those issues might affect the way we design a rule. For example, do we need information about the contractual obligations between PG&E, A&S, and Canadian suppliers prior to implementation of the rules we propose today? Our proposed rules seek to develop a broad regulatory program that hedges the risks associated with such market conditions.

We invite PG&E, CPG, and any other party, to comment on the issues they believe need to be addressed in hearings before implementation of the rules we propose in this decision or other specific rules which they may put forward. We are not seeking a laundry list of uncertainties, but rather <u>specific controversies of fact which might affect the design of the final rules</u>. Our subsequent decision will determine whether hearings are required before adoption of some or all of the final rules.

Findings of Fact

1. R.90-02-008 proposed general guidelines for changing the regulation natural gas utilities, including the regulation of procurement, sales, and relationships with affiliates.

2. R.90-02-008 required respondent utilities to file comments on the proposed general guidelines and sought comments from other parties.

3. SoCal filed, on April 25, 1990, a request to adopt a settlement it had reached with CIG, Salmon/Mock, TURN, the University of California, GasMark and Enron.

4. On April 27, 1990, the parties to this proceeding filed comments on R.90-02-008.

Conclusion of Law

The respondents to this proceeding should be ordered to file, by August 22, 1990 comments on the rules proposed in this decision, and attached as Appendix A. The deadline for comments by other parties should also be August 22, 1990.

INTERIM ORDER

IT IS ORDERED that:

1. The respondents to this proceeding shall file, by August 8, 1990, comments on the rules proposed in this decision and attached as Appendix A. Pacific Gas and Electric (PG&E) shall include in its comments an analysis of the effect of the January 24, 1990 order of the Federal Energy Regulatory Commission (50 FERC 61,067) on the contractual obligations between PG&E, its affiliates, and Canadian gas producers. Other parties who wish to comment on the rules attached as Appendix A must do so by August 8, 1990. Reply comments may be submitted and should be

filed by August 17, 1990. All comments shall be served on all parties to this proceeding.

2. The respondents to this proceeding shall file, and other parties may file, within 60 days of the effective date of this decision, responses to questions raised in Section III of this decision.

This order is effective today.

Dated JUL 18 1990, at San Francisco, California.

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

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

NEAL J. SHULMAN, Executive Director

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PROPOSED RULES FOR GAS UTILITY PROCUREMENT

Gas Sales to Noncore Customers

The gas utilities shall not sell gas supplies to noncore customers except those which subscribe to core services and as permitted under other rules.

The utilities shall not create new noncore marketing affiliates. The utilities shall show no preference for their own affiliates' gas supplies, except as required to fulfill pre-existing contract obligations, and shall treat those affiliates as they would any other gas supplier. PG&E's preference for A&S supplies shall end when its existing contract obligations end.

Core Subscription Service

Each gas utility shall offer a core subscription service. That service shall provide to qualified noncore customers both gas and transportation for gas. Core subscription customers' gas shall have highest priority transportation after core customer gas. Curtailments of transportation among core subscribers shall be according to existing end use priorities. Core subscription customers' cost of gas will equal that offered to core customers. Core subscription customers' cost of transportation will be equal to 125% of the utility's interruptible transportation rate prior to the issuance of a cost allocation and rate design decision for each utility.

In order to qualify for core subscription, customers must make a two-year commitment for 75% of their nominations. Take-or-pay penalties shall be equal to the transportation rate plus 20% of the core weighted average cost of gas (WACOG). Take-or-pay penalties shall apply when, for any reason except bankruptcy, customers take less than their nominated gas volumes.

The initial offering of core subscription service shall provide noncore customers at least two notices of the changes in utility services. The first notice shall be mailed within five days of the effective date of the utility's tariff amendments. Noncore customers shall have 120 days from the date the first notice is mailed to inform the utility of its intention to subscribe to core service. The utility shall make all reasonable efforts to solicit the customer's response. If the customer has not ordered core subscription service within 120 days of the mailing of the first notice, the utility will designate the customer as a noncore

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customer. The customer will retain its pre-existing service prior to receiving a service under the new tariffs or prior to the end of the 120-day period, if the customer does not respond to the utility's notice.

Transportation Services

Core customers shall have highest priority on all interstate and intrastate pipelines. Allocation of pipeline capacity to core customer needs shall be on the basis of least-cost gas purchasing strategics for all utilities.

The utilities shall make available to noncore transportation customers all capacity on their systems which is not reserved for core customers. The gas utilities shall provide both firm and interruptible interstate and intrastate transportation services to noncore customers. The service shall provide highest priority transportation service after core and core subscription service.

Noncore customers using the PGT line shall purchase gas from PG&E's affiliate A&S until PG&E's minimum contract obligations are fulfilled. PG&E shall notify the Commission and its customers when such obligations are met, and shall notify the Commission no later than December 31, 1991 of the status of negotiations with Canadian producers.

The rate for interruptible transportation shall be the existing transportation "default" rate prior to the time the Commission approves a rate design for transportation services. The rate for firm transportation shall equal 120% of the interruptible transportation rate until the Commission has approved a rate design for the service. Rates for firm transportation service shall be tariffed and non-negotiable.

Initial allocation of noncore firm capacity shall be based on customers' pro rata share of historical demand. Pro rata allocation shall not apply to customer volumes which are the subject of long-term contracts. Customers with long-term contracts that wish to use firm transportation service will be allocated firm transportation according to their pro rata shares of historical usage excluding contracted volumes.

Firm transportation customers must make a one year commitment to receive the service and accept a 50% use-or-pay obligation. Use-or-pay obligations will be imposed notwithstanding the reasons for reduced demand, unless the customer is subject to the jurisdiction of a bankruptcy court.

At least until such time as the utilities have implemented capacity brokering programs, curtailments of firm transportation service shall be according to existing end use priorities.

The utilities may transport gas to other utilities in order to assure operational flexibility on utility systems.

<u>Services to Electric Departments of Combined Utilities</u>

Electric departments of combined utilities may purchase from their gas departments' core subscription service up to 15% of the electric department's average annual requirements over the preceding three years. The UEG may purchase transportation as any other noncore customer.

<u>Balancing and Standby Services to Noncore Customers</u>

The utilities shall provide balancing services to noncore customers. The tolerance for balancing services shall be 10% of customer nominations. Customers shall have 30 days from the date of utility notification to reconcile balances. Noncore customers may trade imbalances to avoid liability.

Where positive imbalances fall outside the 10% tolerance for more than 30 days after utility notification, utilities shall purchase noncore customers' overnominations at a rate equal to 50% of the core WACOG.

Where negative imbalances fall outside the 10% tolerance for more than 30 days after utility notification, utilities shall provide standby services to noncore customers. Standby service gas rates shall be equal to 150% of the core WACOG. Standby service shall have the lowest priority during periods of curtailment.

By April 1 of each year, the utilities shall file with the Commission Advisory and Compliance Division estimated capacity allocation between core and noncore customers on each interstate pipeline.

<u>Sales of Excess Core Gas Supplies</u>

The utilities shall sell excess 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.

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<u>Sales of Excess Core Gas Supplies</u>

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