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Decision 90-09-089 September 25, 1990

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

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 adopts final rules for the regulation of the natural gas utilities' procurement practices and related matters. 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.

I. Summary

This decision set forth new rules for utility gas procurement and transportation services, adopting as part of our rules the essential elements of a Settlement filed on August 15. Today's decision is designed to address certain shortcomings of our existing regulatory program by providing firm access to pipeline capacity on an interim basis and by further limiting the utilities' participation in noncore procurement markets.

We adopt today's rules in recognition that our regulatory program requires certain changes to ease the supply problems posed by pipeline capacity constraints. When new pipeline capacity becomes available, and with the development of nondiscriminatory capacity brokering programs, gas markets will grow increasingly competitive as customers gain access to more reliable transportation. We expect circumstances to improve in this regard over the next few years. As they do, these rules will be modified to reflect changed circumstances.

In summary, our decision today changes our regulatory structure in accordance with much of the Settlement and to provide that the utilities shall:

Eliminate their noncore portfolios;

Develop a "core subscription" service which provides bundled gas procurement and transportation services for customers willing to make a two-year commitment and accept a 75% take-or-pay obligation;

Establish four levels of noncore transportation service with varying customer obligations and rates pending the resolution of capacity brokering issues;

Provide noncore customers pro rata access to firm pipeline services in the case of Southern California Gas Company (SoCal); Pacific Gas and Electric Company (PG&E) shall provide access to the Pacific Gas Transmission (PGT) pipeline in the amount of 250 MMcf per day and 200 MMcf per day on the El Paso Natural Gas Company (El Paso) system;

Limit UEG purchases of firm transportation services to 65% of their demand.

In addition, we adopt a two-year cost allocation proceeding and balancing account treatment for 75% of noncore transportation revenues, as proposed by the Settlement.

We opened this proceeding in order to address allegations that the market structure was not competitive in large part because, according to many, the utilities had too many advantages over competitors. The primary reason appears to be, as it has for several years, to be the utilities' exclusive access to firm interstate pipeline capacity. It appeared to us that this lacking access, in combination with utility procurement of gas for noncore customers, dampened prospects for true competition in gas markets. The issue of access to firm transportation cannot be fully resolved until the capacity brokering programs have been put into place. As we stated in R.90-02-008 and D.90-07-065, however, competition would be furthered by limiting the utilities' participation in the noncore procurement market.

II. 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.

After receiving comments on R.90-02-008, we issued a set of proposed rules in D.90-07-065 and asked for comments on the proposed rules. The rules proposed in D.90-07-065 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.

On August 15, 1990, several parties to the proceeding filed a Settlement. On the same day, the parties to an earlier Settlement, which we addressed in D.90-07-065, withdrew their offer of Settlement. Parties to the August 15 Settlement are PG&E, California Industrial Group (CIG), California League of Food Processors and California Manufacturers Association, Mock Resources, Inc. (Mock), San Diego Gas and Electric Company (SDG&E), Toward Utility Rate Normalization (TURN), GasMark, Inc. (GasMark), SoCal, and Enron Marketing, Inc. (Enron).

The following parties filed or submitted comments on the rules proposed in D.90-07-065 or filed comments on the August 15 Settlement:

Alberta Petroleum Marketing Commission (APMC)
Berry Petroleum Company (Berry)
Bonus Gas Processors, Inc. (Bonus)
California Asphalt Pavement Association (CAPA)
California Cogeneration Council (CCC)
California Department of General Services (DGS)
California Energy Commission (CEC)
California Gas Producers Association (CGPA)
California Industrial Group, California League of Food Processors, and California Manufacturers Association (CIG)
Canadian Petroleum Association (CPA)
Canadian Producer Group (CPG)
Capitol Oil Corporation (Capitol)
City of Long Beach
City of Palo Alto
Coastal Gas Marketing Company (CGM)
Cogenerators of Southern California (CSC)
Division of Ratepayer Advocates (DRA)
El Paso Natural Gas Company (El Paso)
Enron
Government of Canada
Hadson Gas Systems, Inc. (Hadson)
Independent Petroleum Association of Canada (IPAC)
Indicated Producers
Kern River Gas Transmission Company (Kern River)
Matich Corporation (Matich)
Ministry of Energy, Mines and Petroleum Resources Province of British Columbia (Ministry)

Mobil Natural Gas, Inc. (Mobil)
Mock
Natural Gas Clearinghouse (NGC)
Oryx Energy Company, Shell Western E&P Inc., Texaco Inc., Union Pacific Resources Company (Oryx)
PG&E
Pan-Alberta Gas Ltd. (Pan-Alberta)
Phillip Morris Management Corporation (Phillip Morris)
Phillips Petroleum Company, Phillips 66 Natural Gas Company, and Phillips Gas Marketing Company (Phillips)
PSI Gas Marketing, Inc. (PSI)
Salmon Resources Limited (Salmon)
SDG&E
School Project for Utility Rate Reductions (SPURR)
Southern California Edison Company (Edison)
SoCal
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)
Tehachapi Cummings County Water District (Tehachapi)
TURN
Transwestern Pipeline Company (Transwestern)
United States Borax and Chemical Corporation (Borax)

This decision does not summarize all of the comments of all of the parties because of their large number and because the parties' views have already been partially summarized in D.90-07-065. The decision does, however, attempt to describe all perspectives and the rules we adopt today reflect our consideration of all parties' views.

III. The Settlement

We encouraged the parties to attempt to negotiate their differences in this rulemaking. We hoped that a settlement would represent to the greatest extent possible the interests of a cross-section of the parties. A Settlement was filed August 15. The Settlement addresses many issues relating to procurement, transportation priority, rate design, and utility incentives. It is obvious that the parties worked long and hard to reach agreement on these issues. Its signatories include representatives of consumers (CIG, California League of Food Processors, California Manufacturers' Association, TURN), utilities (SoCal, PG&E, SDG&E) and brokers (Mock, GasMark, Enron).

While the Settlement may represent a reasonable compromise to the signatories, numerous parties object to it. Among those who oppose the Settlement are consumer and utility representatives (DRA, Long Beach, and Palo Alto), cogenerators (CCC, CSC, US Borax), gas brokers (Sunpacific, PSI, Natural Gas Clearinghouse, PSI), gas producers (Indicated Producers, Capitol Oil, Phillips), governmental agencies (CEC, State of New Mexico) and an interstate pipeline (El Paso). Several other parties oppose certain elements of the Settlement (DGS, Kern River).

Whether ratepayers and the public interest generally would benefit in the short term and over the longer term from the terms of the Settlement is a matter of great concern to us. A contested settlement may serve the public interest; on the other hand, because a settlement represents a series of trade-offs between parties who naturally seek to promote their own interests, a settlement reached on issues as complex as those before us today may not automatically serve the public interest.

TURN asks the Commission to "consider the settlement in the same way that the participants have -- from the perspective that it is better to achieve a broad consensus of support...than to 'win' on every single point." This is an unexpected comment coming from TURN, which has opposed many broadly based settlements on the grounds that they did not represent the public interest. The Commission is not a party to this proceeding and its concerns may differ from those of individual parties or coalitions the parties may build. The Commission must consider whether the Settlement as proposed would establish a program that is fair and economically efficient until new pipeline capacity is available from major producing regions. To the extent a settlement can accomplish this objective must seriously consider such proposals.

We therefore are obligated to consider the several elements of the Settlement to determine whether they are reasonable. As we recently stated:

> "In judging such settlements the Commission retains the obligation to independently assess and protect the public interest. Parties to a settlement may chafe at what they perceive as intrusion on bargained-for deals and may believe that this Commission should simply take their word that the settlements serve the interest of the public in addition to the interests of the settling parties. However, settlements brought to this commission are not simply the resolution of private disputes such as those that may be taken to a civil court. The public interest and the interests of ratepayers must also be taken into account, and the Commission's duty is to protect those interests.
>
> "In evaluating settlements, one factor we consider is the range of interests represented by the parties to the settlements and any opposition to the settlements, as well as the settlement itself." (D.90-08-068, pp. 27-28.)

For these several reasons, we have considered the Settlement elements to determine their reasonableness as part of a package of regulatory policies. We will adopt the Settlement with minor changes. Those we do not adopt are those which we believe cannot be considered outside the scope of other proceedings or which compromise our objectives to promote competition and protect the core from unnecessary risk.

Although we do not adopt some elements of the Settlement, we need not, as the Settlement suggests, provide the parties with an opportunity to negotiate new provisions or withdraw from the Settlement. This is because the provisions we adopt have been subjects of this rulemaking and several rounds of comments by the parties. We adopt the Settlement provisions as we adopt any other provision of our regulatory program and after notice and opportunity to be heard. Moreover, the parties should not withdraw from the Settlement because we do not adopt it in total. There is no assumption that any party concurs with any or all of the program elements we adopt today beyond the positions they have advocated as part of the record of this proceeding.

This decision sets forth the parties' views on the rules proposed by D.90-07-065 and compares our proposed rules with those which are included in the Settlement.

IV. Industry Structure

A. Noncore Procurement Activities and Marketing Affiliates

D.90-07-065 proposed to eliminate the noncore portfolio and prohibit utility noncore marketing affiliates. The proposed rules stated:

> 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.

The proposed rules reflected a nearly unanimous view of commenting parties that the utilities should eliminate their noncore portfolios because of the potential for the utilities to discriminate in favor of their own noncore customers. For the same reason, we rejected proposals to permit the utilities to sell gas to noncore customers out of the core portfolio except as core subscription customers, discussed in Section IV B.

The proposed prohibition on new noncore marketing affiliates addressed our concerns over inter-affiliate transactions and the difficulty of regulating them. Moreover, no party argued that utility gas sales were required to assure stable and competitively-priced gas supplies for noncore customers.

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

a. <u>The Settlement</u>

The Settlement would eliminate the existing noncore portfolio. It leaves to the Commission's discretion whether to permit noncore customers to purchase gas from a single portfolio. It provides a list of regulatory guidelines for new or existing marketing affiliates (which do not apply to A&S as required to "effectuate the procurement arrangement for supply service over PG&E's northern system as provided for in the settlement"):

> Marketing affiliates will be structurally separated from the utility, with necessary requirements to prevent cross-subsidization of unregulated activities;

> Marketing affiliates will be treated the same as other unregulated gas marketers, brokers, etc. by the regulated utility in all transactions including pipeline nominations, and access to storage, firm capacity, and information about customer demand and capacity availability;
>
> Costs from the marketing affiliate will not be allocated to core rates or noncore transportation rates, except as necessary to effect the A&S supply arrangement set forth in the settlement.

b. PG&E

PG&E believes that restricting its ability to sell gas to noncore customers through a separate affiliate is "discriminatory" and may restrict gas-to-gas competition. According to PG&E, the prohibition may also hamper its ability to restructure its existing supplies.

c. SoCal

SoCal argues that it would be acceptable to impose a prohibition on utility procurement services to interruptible noncore customers but only if the Settlement as a whole is adopted. It believes limiting its procurement role will increase its business risk because it will have to rely on the unregulated market to serve noncore customers with reliable supplies which SoCal relies upon to keep throughput high and retain associated revenues.

SoCal opposes the prohibition of utility marketing affiliates and believes the Commission may be beyond its jurisdiction if its rules interfere with federal law.

d. DRA

DRA supports the proposed rules on the noncore portfolio and new marketing affiliates. It argues, however, that the Commission should clarify that Alberta and Southern (A&S),

PG&E's Canadian marketing affiliate may not expand its operations into California, for example, by brokering supplies to end-users from sources other than Canada.

e. TURN

TURN supports the proposed prohibition on new marketing affiliates but seeks clarification on treatment of already existing noncore marketing affiliates. It suggests existing affiliates either be prohibited from doing business in the utility's service territory or that strict regulations be adopted to prevent abuses.

TURN also advises close Commission oversight to assure that core customers do not bear costs properly attributable to noncore marketing efforts by A&S if A&S becomes a direct seller in PG&E's noncore market (this could occur in order for A&S to ameliorate take-or-pay liability). TURN supports CIG's list of rules, except that it suggests the rules be expanded to absolutely bar sharing of employees by a utility and its marketing affiliate.

f. Industrial Customers

Like TURN, CIG believes the proposed rules need to address the activities of existing affiliates which are engaged in the production and sale of natural gas inside and outside the state. CIG proposes a set of rules for that purpose. CIG also comments that the Commission should recognize that A&S will have a limited procurement role in facilitating noncore customers' access to Canadian supplies.

g. UEG and Wholesale Customers

Edison argues that supply problems of customers result mainly from inadequate pipeline capacity and will not be alleviated by elimination of the noncore portfolio and a prohibition on marketing affiliates.

Southwest favors elimination of the noncore portfolio only if the utilities are permitted to create marketing affiliates. It believes the Commission has failed to recognize the benefits of utility participation in noncore markets and strongly objects to any limits on the ability of the utilities to create marketing affiliates.

SCUPP strongly supports the proposed rules on noncore sales and marketing affiliates. Long Beach favors unregulated utility marketing affiliates as long as equal access is available to affiliates and their competitors.

h. DGS

DGS generally agrees with the Commission's proposal to restrict utility sales of gas to noncore customers and to prohibit the creation of utility marketing affiliates.

i. CEC

CEC supports the proposed rules' prohibition on the creation of new marketing affiliates and the elimination of the noncore portfolio.

j. Independent Gas Producers and Marketers

Bonus favors new marketing affiliates, which are fully separated, to permitting the utilities to market gas to noncore customers through a core subscription service. It believes that as long as a utility offers gas to noncore customers, its price will be a ceiling for the market. According to Bonus, this price will be lower than competitors can offer because it will not include all of the costs of providing gas.

Hadson, Phillips and Indicated Producers support the proposed rules regarding the noncore portfolio and the treatment of marketing affiliates. Phillips recommends that the Commission oversee the activities of existing affiliates to prevent anti-competitive activity.

NGC does not object to the creation of new utility marketing affiliates.

k. <u>Pipeline Companies</u>

Kern River generally endorses the proposed rules.

1. <u>State of New Mexico</u>

The State of New Mexico agrees with the proposed rules on the subject of noncore sales and affiliates and opposes those in the Settlement as failing to promote competition. New Mexico believes the Settlement retains the utilities' preferential competitive position by allowing their marketing affiliates to compete with alternative suppliers.

2. <u>Discussion</u>

We have considered the Settlement provision which would permit marketing affiliates and the comments supporting the provision. We continue to have concerns about the risks posed by utility marketing affiliates and are not convinced that the they are required to assure a stable source of gas supplies for noncore customers. We will therefore prohibit the establishment of new utility marketing affiliates. We will reconsider our rule only if the utilities can demonstrate that the gas market in California is unable to provide reliable and adequate gas supplies to noncore customers.

At the suggestion of TURN and CIG, we will also adopt specific rules for the activities of existing affiliates.

Consistent with the comments of all parties, and our proposal in D.90-07-065, our new rules will not permit a separate noncore portfolio.

Our adopted rules for utility gas marketing affiliates are:

> Utility gas marketing affiliates shall maintain separate facilities, books and record of account, which shall be available for inspection by the Commission staff upon reasonable notice;
>
> Employees of the gas utilities shall not perform any functions for utility affiliates except those services which they offer to

others on an equal basis, and utilities shall not share employees with marketing affiliates;

Gas utilities shall not reveal to their affiliate any confidential information provided by customers or nonaffiliated shippers to secure service. Confidential utility information shall be made available to all shippers if it is made available to utility marketing affiliates;

Utilities shall identify and remove from their cost of service all costs, including administrative, general, operating and maintenance costs, incurred by a marketing affiliate, and thereafter prohibit the booking to the partner utilities' system of account costs incurred or revenues earned by the marketing affiliate;

Utilities shall not condition any agreement to provide transportation service, to discount rates for such service, or to provide access to storage service or interstate pipeline capacity to an agreement by the customer to obtain services from any affiliate of the gas utility, except for the provisions contained herein respecting the direct purchase of gas by noncore customers from PG&E's affiliate A&S for the period of years specified herein;

Utilities shall disclose in reasonableness reviews or other such regulatory proceedings each transaction between the parent utility and its marketing affiliate, with sufficient information on the terms and conditions of each transaction as to permit an evaluation of the nature of such transactions. The same information shall be provided to Commission staff at any time upon reasonable notice;

Each gas utility shall submit, within 90 days of the effective date of this decision, a written report, available for public inspection, stating how the utility plans to implement these standards of conduct with respect to any existing affiliate activities in the California market.

> Gas utilities shall not procure gas for or sell gas to noncore customers except as otherwise permitted by these rules.

B. <u>Core Subscription Service for Noncore Customers</u>

D.90-07-065 proposed to eliminate the current core-elect option and replace it with "core subscription" service. The service was intended to provide a reliable, premium service for customers who do not want competitive options and who are willing to make a commitment to the service.

We stated our view that 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 would in turn reduce utility risk and improve operational and financial planning.

D.90-07-065 also stated that the purpose of the core subscription service would not be to provide noncore customers with access to utility gas supplies when they happen to be priced comparatively low, or a means to increase utility loads. The purpose of the core subscription service would not be to provide customers with yet another competitive option on a short-term basis.

The proposed core subscription service would require a 75% take-or-pay commitment and a two-year time commitment for a combined transportation and procurement service. We rejected proposals to limit take-or-pay obligations which arise for reasons other than switching to alternate fuels or energy sources on the grounds that individual customers, rather than the general body of ratepayers, should bear the risk from their variable demand.

Our proposed rule gave core subscription transportation priority over all transportation services except the core. Curtailment within the core subscription class would be according to existing end use priorities. The proposed rules set the rate for the core subscription at the core WACOG plus 125% of the interruptible transportation rate.

Core subscription service would be bundled: customers who purchase it would receive both procurement and transportation services. We did not propose an unbundled procurement service for noncore customers, believing that it would likely promote too much utility participation in noncore markets and thereby frustrating our objective of more competition in those markets.

We proposed the following rules for core subscription:

> 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.

1. Positions of the Parties

a. Settlement

The Settlement proposes a core subscription service which would offer bundled transmission and gas supplies only to customers who choose the highest priority noncore transportation service.

Customers purchasing the core subscription service would be required to make a one-year commitment if the existing ACAP procedure is continue, or a two-year commitment if a biannual cost allocation proceeding (BCAP) is adopted. The Settlement recommends a two-year cycle for cost allocation review. Take-or-pay obligations of 75% would be relieved in the event of force majeure, curtailments of service interruptions imposed by the local utility, or essentially any demand reduction not related to fuel switching.

The gas rate for noncore customers would be adjusted monthly to equal the recorded weighted average cost of gas (WACOG) for the prior month plus a brokerage fee of $.07 per decatherm (except SDG&E whose brokerage fee would be calculated in a subsequent proceeding). The utilities would recover all gas costs in balancing accounts. Revenues from brokerage fees would also be subject to balancing account treatment. Revenues from the bundled transportation element would be subject to balancing account treatment with 25% of imbalances allocated to utility shareholders, discussed further in Section IV.C. on noncore transportation.

b. PG&E

PG&E generally supports the core subscription service put forth in the proposed rules except that it recommends that core transportation receive the same priority as the firm transportation option in order that utility procurement services receive no higher priority than those of competitors. Consistent with this provision, PG&E suggests the prices for firm and core subscription transportation should be set at the same level.

PG&E suggests the core WACOG for core subscription customers be changed monthly to reflect the utility's best estimate of the price of gas in the next month.

PG&E also advocates that the core subscription service be a default service during the initial "open season" period. It comments that many noncore customers operate under bureaucratic decision-making processes which may prevent timely contracting.

c. SoCal

SoCal is "astonished" that the Commission would tie the availability of firm transmission service with procurement service. SoCal supports the Settlement's provisions which provide a bundled noncore service which offers the same priority transmission as the firmest unbundled transmission service.

SoCal recommends the Commission set the take-or-pay penalty at 14%, rather than 20% of the WACOG, until record evidence on costs has been received.

SoCal supports the Settlement's proposal to waive take-or-pay obligations for any force majeure event and believes the bankruptcy criterion for forgiveness in the proposed rules is inappropriate.

d. DRA

DRA supports the Commission's proposal for core subscription, including the Commission's objectives and its reasoning for rejecting the Settlement's proposal on the grounds that encourages too much core subscription. It agrees that ratepayers as a group should not shoulder the risk of business swings and other events affecting individual customor demand and thereby triggering take-or-pay obligations.

DRA objects to setting the take-or-pay penalty at the transportation rate plus 20% of the core WACOG on the grounds that it is not cost based. DRA recommends that instead of a 20% penalty, the Commission continue the cost-based rules currently in effect. As stated in D.86-10-010,

> "Elected core procurement customers who do not use their full contracted qualities on a yearly basis will be liable for unavoidable or minimum charges to reflect any cost which the utility incurs as a result, excluding any costs allocated to transmission charges."

DRA opposes the Settlement provisions for allowing noncore customers to purchase out of a single portfolio. According to DRA, this effectively consolidates the noncore and core portfolios placing more risk on the core. DRA states the Settlement provisions would also expand the role of the utilities in noncore procurement by permitting sales of long-term gas supplies in that market, contrary to the Commission's stated objective of limiting the utilities' participation in the noncore gas markets.

e. TURN

TURN comments that the proposed rules would unnecessarily create a capacity problem by assigning core subscription service a higher capacity priority than firm noncore transmission service. TURN believes core subscription service and firm noncore transmission should be assigned on the same pro rata basis, subject to curtailment by end use priority.

TURN also believes the Commission should accept the view that higher loads enhance the utility's bargaining power in purchasing gas, with resulting benefits for core customers.

TURN urges the Commission to set the core subscription gas cost at the actual recorded WACOG lagged one month. The reason for this pricing principle, which was adopted in D.89-04-080, is to avoid large undercollections which would encourage customers to opt out of the core service to avoid the undercollection. TURN believes this logic would apply under the new regime.

TURN recommends that if the core subscription commitment is two years, the ACAP cycle should also be two years.

f. <u>State of New Mexico</u>

The State of New Mexico believes the core subscription service proposed by D.90-07-065 allows the gas utilities to offer a premium service that other suppliers will not be able to match and that will not promote competition in gas markets. The State of New Mexico believes the core subscription service is too attractive and that the Commission should examine in hearings the extent of PG&E's obligations to buy Canadian gas.

g. <u>DGS</u>

DGS recommends the Commission allocate core subscription revenues to the noncore firm and interruptible transportation rates. DGS believes the differential between core subscription transportation rates and firm transportation rates is too narrow considering the superiority of the core subscription service. It recommends providing core subscription customer with the same transmission priority of firm noncore customer.

h. CEC

CEC supports the Commission's proposals regarding core subscription and the objectives the Commission sets forth in designing the service.

i. Industrial Customers

CIG believes the proposed core subscription service will provide "unbeatable" marketing advantages to tho utilities. CIG is primarily concerned with core subscription's transmission priority over other noncore customers combined with the utilities' access to to capacity and specific receipt points on behalf of the core. According to CIG, the proposed core subscription service should combine the customer's two-year commitment with a two-year stable transmission rate, as the Settlement provides.

CIG argues that the take-or-pay penalties should not apply when customers cannot buy gas from the utilities because the utility has curtailed the customer, and also when force majeure conditions occur. CIG argues that industrial customers should not be liable for reduced gas demand resulting from plant closures, maintenance shutdowns, business conditions, or crop failures, among other things.

Matich opposes any change to core services for noncore customers which would increase its costs and expresses concern over the quality of service it may receive by purchasing gas from nonutility firms. Tehachapi makes similar comments.

Philip Morris recommends that the take-or-pay obligations be waived for any force majeure event and that the Commission permit a customer to makeup an accumulated take-or-pay obligation. It also asks the Commission to clarify that, after adoption of final rules, core-elect customers would have the right to terminate their core-elect contracts and have the option of becoming noncore customers or core subscription customers.

CAPA comments that the core subscription service proposed by the rules is too restrictive.

j. <u>Pipeline Companies</u>

El Paso supports the proposed rules generally on the subject of core subscription but comments that the 75% take-or-pay requirement may be onerous for small noncore customer with varying load factors. El Paso suggests that subscribers to the core be allowed to adjust their contract quantities by a specified annual amount even if a charge is assessed for changes in volumes. It also suggests the rules permit customers to subscribe to capacity based on seasonal, rather than annual, nominations to permit some flexibility.

Kern River supports generally the core subscription rules but suggests the procurement rate should include the $.07 per decatherm procurement fee included in the Settlement. It also believes the spread between core transmission and interruptible transportation is too low to reflect the value of each.

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

Sunpacific believes core subscription should be unbundled and suggests a "smooth continuum" of service extending from core level service to interruptible noncore service. According to Sunpacific, the parties available to supply those services should not be differentiated based on the services they are allowed to supply but based on those they choose to supply. Sunpacific recommends hearings on issues related to the further unbundling and pricing of utility services. It also suggests that the Commission should require core subscription customers to elect volumes which should not vary month by month and thereby permit those customers to get a disproportionate portion of their gas in the winter months from the core subscription service.

Indicated Producers supports a very limited core subscription service which would not be offered to UEGs or large municipal utilities. It believes the Settlement provisions are too attractive to have the desired effect of discouraging price-chasing. The Commission should, according to Indicated Producers, adhere to its earlier-stated goal of permitting utility sales to the noncore only as a "safety net" service.

Phillips generally supports the proposed core subscription rules, but suggests the rules provido for a one-time opportunity for core subscription customers to opt out of their contracts is capacity brokering or assignment rulos are implemented which make it viable for some core subscribers to purchase their own gas. Phillips opposes the Settlement's provisions for core subscription.

Salmon and Hadson generally support the proposed core subscription rules.

1. UEG and Wholesale Customers

Edison generally supports the proposed core subscription rules but believes the provision for take-or-pay foregiveness is too restrictive and the transmission rate is too low in view of the relative value of the service.

Southwest seeks clarification on whether the take-or-pay penalties will be calculated on peak day, monthly, or yearly nominated volumes.

SCUPP believes the core subscription service proposed in D.90-07-065 is too attractive and favors the core subscription proposal in R.90-02-008.

Long Beach opposes the core subscription program as unnecessary and damaging to competition.

2. Discussion

Consistent with our observations in D.90-07-065, we continue to believe that core-subscription should be a reliable, premium service for noncore customers that do not seek competitive alternatives. With that in mind, we will adopt a core subscription service that is substantially similar to that proposed by the Settlement.

The Settlement's proposals for setting transportation and gas rates are reasonable. We also agree with the Settlement and other parties that core subscription should receive the same transportation priority as the highest priority noncore transportation service, rather than a higher priority as our proposed rules would have required. Equal priority for core subscription customers and high priority noncore customers will better promote competition in procurement markets.

We agree with the Settlement parties that a two-year commitment makes most sense with a two-year cost allocation proceeding, which the parties have termed a "BCAP."

Our adopted rules on forgiveness of use-or-pay transportation obligations differ somewhat from those proposed by the Settlement. The Settlement's provisions would relieve customers from use-or-pay obligations for what appears to be any circumstance, except fuel switching, which would reduce demand. It is not reasonable to impose on the general body of ratepayers this much risk for demand reductions in transportation services. The utilities are obligated to pay certain demand charges for interstate pipeline transportation. It is therefore reasonable to require individual customers to share some of the risk associated with their demand variations. Unless the use-or-pay provision in the Settlement reasonably reflects utility risk, the core subscription service will not encourage customers to make choices which will promote competition. We adopt the Settlement provisions regarding the circumstances under which procurement take-or-pay obligations may be relieved but require noncore transportation customers to absorb the risk associated with demand reductions occurring for reasons other than force majeure events.

To respond to PG&E's suggestion, we make a minor modification to provide that core subscription service is a "default" service for customers who were originally core-elect customers and who do not notify the utility regarding changing service to core subscription or transportation-only service. We believe this provides a convenience for existing core-elect customers which does not unreasonably advantage the utilities.

> Each gas utility shall offer a core subscription service. That service shall provide to qualified noncore customers both gas and transportation for gas. Noncore customers customers may take all or a portion of their requirements as core subscription customers.
>
> Core subscription customers' gas shall receive the same priority as the highest level priority for noncore customers. Curtailments of transportation among core subscribers shall be according to existing end use priorities. Core subscription customers' cost of transportation will be equal to the rate for the utility's highest priority noncore transportation rate.
>
> Core subscription customers' cost of gas will equal that offered to core customers except that the price shall be set each month at the actual recorded WACOG lagged one month, as set forth in D.89-04-080. In addition, core subscription customers shall pay a brokerage fee in the amount adopted in utilities' cost allocation proceedings or other appropriate proceedings.
>
> In order to qualify for core subscription, customers must make a two-year commitment for 75% of their annual nominations. Nominations may be for full requirements or partial requirements. Partial nominations shall be a stated annual volume which may be adjusted seasonally in accordance with the customer's historic usage patterns as provided in D.88-03-085, Ordering Paragraph 2. Utility sales gas will be deemed to be the first gas through the meter.
>
> Take-or-pay penalties for procurement services shall be forgiven to the extent the customer's reduced gas consumption is due to force majeure, curtailments, or service interruptions imposed by the utility.

Take-or-pay penalties for procurement services shall be equal to the utility's average cost of gas inventory charges or similar unavoidable costs, if any. Until issuance of a decision setting forth a cost-based charge, the take-or-pay procurement service charge will be set at 14% of the current WACOG of the utility gas supply portfolio. Use-or-pay penalties for core subscription transportation services shall be equal to those imposed for the highest level noncore transportation service option.

To the extent that the UEG department of a combined utility purchases gas from sources other than the utility portfolio, it must do so by contracts separate and distinct from the contract underlying the utility's system supply. The utility's UEG will pay the cost of gas under such contracts. Any instances in which the gas and electric departments of a combined utility purchase gas under separate contracts from the same or affiliated suppliers shall be fully detailed in the utility's annual reasonableness review report.

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 except that customers who were previously core-elect customers will be designated core subscription customers. Customers who do not respond to the utilities notice before the end of the 120 notice period will retain their pre-existing services during the 120-day period.

Utilities will file cost allocation applications on a two-year cycle.

> A utility may file an advice letter requesting a core rate adjustment 45 days before the end of the first year of its cost allocation test year if the percentage adjustment to bundled core rates required to amortize the first year's net over or undercollection in the core PGA and core Fixed Cost Accounts (nine months recorded and three months forecasted) over one year of previously adopted core sales would exceed 5%. Such an advice filing must include completed workpapers and shall not propose any change in adopted cost allocation or rate design other than the rate changes necessary to amortize the net core over- or undercollection.

C. <u>Noncore Transportation Services</u>

D.90-07-065 agreed with several parties that some type of firm transportation for noncore customers is required at least until the utilities have implemented capacity brokering programs. We proposed that the utilities establish firm transportation which would have highest priority after core and core subscription volumes. An interruptible service would be provided at a lower rate. The firm rate would be priced equal to 120% of the rate for interruptible service until a new rate design for the utilities' transportation services was considered in I.86-06-005. Firm and interruptible rates would 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 would be according to existing end use priorities at least until the utilities have implemented capacity brokering programs.

Pending resolution of rate design issues in I.86-06-005, we proposed to set the firm transportation rate for core subscription equal to 125% of the interruptible rate. Rates for this service would 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.

D.90-07-065 found that one of 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 may be priced competitively with gas from other sources, we stated our view 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.

Our proposed rules addressed in part this issue by directing PG&E to make available to noncore customers all PGT capacity which is not reserved for core requirements. Core customers would have first priority on the PGT line or whatever system offers the best combination of economic and reliable gas supplies to core customers.

Under the rules proposed in D.90-07-065, customers wishing to move gas over PGT would engage in purchase 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).

> 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.

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.

1. Positions of the Parties

a. The Settlement

The Settlement provides that procurement and transmission services to noncore customers would be unbundled, as discussed in Section IV.A. Under the terms of the Settlement, noncore customers would have four transportation options, each with different terms and conditions.

> Service Level 1 -- core service.
>
> Service Level 2 -- firm service for noncore customers under an annual contract with a 75% use-or-pay obligation and a use-or-pay penalty equal to 80% of the firm transportation rate applicable to the customers. This service shall require a two-year commitment if the Commission adopts a biennial cost allocation proceeding.
>
> Service Level 3 -- interruptible service under an annual contract with a 75% use-or-pay obligation and a use-or-pay obligation penalty equal to 60% of the customer's applicable transportation rate.
>
> Service Level 4 -- interruptible service subject to a 75% use-or-pay obligation and a use-or-pay penalty equal to 30% of the customer's applicable transportation rate.
>
> Service Level 5 -- interruptible service for nomination periods of less than a full month with no use-or-pay obligation.

The Settlement provides that use-or-pay penalties will be forgiven to the extent the customer's usage falls below the 75% level due to force majeure conditions, curtailments or service interruptions imposed by the utility or transporting pipeline, required maintenance of customer's facilities, and idling of customer's facilities (including plant closures) due to economic conditions or variations in agricultural crop production.

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 would make every effort to purchase gas supplies identified by individual customers, which the utility would resell to the customer.

For SoCal, the capacity available on the Transwestern and El Paso lines would be all capacity except that retained for core customers on a pro rata basis. For PG&E, 450 MMcf per day would be available to noncore transportation customers (other than PG&E's electric department), 250 MMcf per day of which would be the PGT, and 200 a day on El Paso. SDG&E's long-term contract with SoCal will remain in effect pursuant to Resolution G-2921.

Under the terms of the Settlement, rates for Service Levels 2 through 5 will consist of the existing customer charge and a simple volumetric rate. Demand charges would be eliminated for all industrial customers except UEGs. The charge for Service Level 2 will be the default rate plus a surcharge of 12 cents per decatherm and the rate would not be negotiable. Charges for Service Levels 3 through 5 would be the default rates, subject to negotiation. The revenues from the 12 cent surcharge will be credited on a forecast basis against the default rates applicable to customers in Service Levels 3 through 5. A tracking account will be established to protect the utilities from forecast errors.

Curtailment would be according to end use priority for Levels 2 and 3. The Settlement signatories ask the Commission to resolve the curtailment method for Levels 4 and 5.

The Settlement provides that utilities may negotiate long-term contracts for customers purchasing Service Level 2 transportation.

Under the terms of the Settlement, the provisions for service levels, rate design, and use-or-pay obligations could not be changed until August 1, 1994, notwithstanding the outcome of the capacity brokering proceeding in R.88-08-018 and the rate design review in I.86-06-005. Access to PG&E's transportation system would also remain in place until August 1, 1994.

The Settlement provides that the risk for 75% of transportation revenues will be borne by ratepayers.

b. PG&E

PG&E believes the proposed formula for setting firm and interruptible transportation services would result in interruptible rates that would be too high to avoid discounting. PG&E suggests that a fixed amount be added to the interruptible rate. Revenues from the additional charge would be credited to the interruptible service to determine the interruptible rate. PG&E believes the amount should be determined in hearings but estimates the "adder" would be about $.15 per decatherm.

PG&E agrees with the priority provisions for core but recommends that the rule be modified to state that the utilities should use their rights on interstate pipelines on behalf of core customers before they provide service to their noncore customers. This modification would recognize that the utilities do not determine priority on interstate pipelines. It also suggests the rule should specify that all capacity must be recallable to preserve core service, if required.

PG&E opposes the proposed rule which would require the utilities to make available to noncore customers all capacity which is not reserved for core customers. PG&E states its willingness to provide 300 MMcf/d of firm interstate and intrastate transportation (half on PGT and half on El Paso) available for noncore use.

PG&E comments that it cannot provide interstate transportation service or even assign their rights until a capacity brokering program is implemented. The firm service must therefore be at the customer's burner tip. PG&E supports the buy/sell arrangements during a transition period to allow noncore customers to purchase Canadian supplies, but warns that minimum contract obligations are annual.

PG&E adds that the rates should allow PG&E to recover its existing revenue requirement and that all rates should be tariffed and nonnegotiable except where special contracts are required.

PG&E recommends the Commission adopt balancing account treatment for all transportation and gas costs now, rather than waiting for additional comments on incentives.

PG&E comments that there should be no "set aside" for long-term contracts, which the proposed rules appears to provide for. It proposes instead that the pro rata allocation of firm service shall apply to all customers volumes regardless of the length of the contract term. PG&E further proposes that volumes under existing long-term contracts receive interruptible priority unless those customers agree to the firm rate.

PG&E advises that the use-or-pay level of firm transportation should equal the take-or-pay provision of the core subscription, 75%.

Finally, PG&E argues that the report to the Commission Advisory and Compliance Division be submitted on a date to correspond to the service nomination deadline for noncore customers to make their annual and biannual service choices.

c. <u>SoCal</u>

SoCal agrees that the core market should always receive the most secure service. SoCal strongly urges the Commission to reconsider, however, its propose rule that would require the core to receive priority for lowest cost gas supply routes. SoCal believes the rule as proposed would frustrate Commission goals to promote competition, especially for Canadian supplies. SoCal therefore recommends a pro rata access between core and noncore customers for pipeline capacity and for the constraint points on the pipelines.

SoCal believes the Settlement's 12 cent per decatherm premium for firm transmission service is much clearer than the proposed rules' rate differential for firm and interruptible. SoCal also advocates the transmission service use-or-pay obligations of 75% of the volume at 80% of the rate for core subscription and firm transmission service, which are more conservative than the proposed rules.

SoCal recommends that until the capacity brokering programs are in place, the Commission should retain the end-use priority system as a "tie breaker" for partial curtailments for interruptible transmission services because it is easy to administer and is in place.

Finally, SoCal believes the Commission should change noncore customer rate design by eliminating demand charges which SoCal argues are very complex and do not fulfill any function.

d. DRA

DRA recommends that core customers should receive a pro rata share of the utilities' capacity rights on the interstate pipelines, rather than receiving highest priority on all systems.

On the issue of firm and interruptible services, DRA believes the implementation problems associated with rate setting will slow down the process of providing firm service. Rather than undertake this process, DRA urges the Commission to proceed immediately to implement capacity brokering. It also states its view that open access can only be achieved if the utilities relinquish the interstate capacity that is not needed to serve the core.

DRA strenuously objects to the Settlement's provisions for transportation services, particularly elements related to rate structure, which eliminate the two part demand charge in favor of an all volumetric rate. DRA believes this change in rate design would promote inefficiencies and preempts the rate design and cost allocation review in I.86-06-005.

DRA also believes the Settlement's provisions for access to PG&E's pipeline capacity is arbitrary and too complex for individual customers to use. DRA also comments that because curtailments have mainly affected only P5 customers, the Settlement service levels may do little more than require some customers to pay more for a service which is no more firm than existing services.

According to DRA, EOR customers get unwarranted special treatment under the terms of the Settlement because they are automatically placed at Service Level 3 and can upgrade to firm service by paying 75% of the firm cogeneration default rate. DRA believes there is no rationale for serving EOR customers ahead of UEGs and no rationale for providing deep discounts to EOR customers while requiring UEGs to pay fully allocated costs plus interstate demand charges.

DRA strongly objects to the seemingly automatic cost recovery the Settlement would provide the utilities for administrative costs relating to the interim arrangement, the transportation balancing account, and the crediting of surcharges to avoid forecasting risk. It believes these balancing accounts reduce risk too much considering the protections the utilities already have because (1) only 20-25% of the utilities' base rate revenue requirement is allocated to the noncore; (2) the insulation from revenue variations as a result of demand charges; (3) the balancing accounts associated with EOR revenues. According to DRA, the utilities are shielded from risks associated with between 72 and 84% of system throughput. The additional balancing account would shield them from the risk associated with 75% of the remainder. DRA believes the new transportation balancing account combined with the tracking accounts designed to shield the risk of forecasting eliminates the incentives inherent in the existing system.

e. TURN

On the subject of transportation, TURN believes that the use-or-pay level should be higher but the penalty charge should be less than the full rate.

TURN also believes the Commission should abandon the percentage rate differential between firm and interruptible transmission service. It proposes a twelve cents per decatherm firm service surcharge, as proposed by the Settlement. TURN comments that the offsetting discount from the default rate increases as more customers select firm service, a result which is consistent with economic theory. TURN believes the Commission's proposed 20% fixed differential is arbitrary and may not reflect market values.

TURN recommends that the Commission require Service Levels 4 and 5 to be curtailed according to the level of their negotiated rates: customers paying more for service would get priority over those at lower levels. This would maximize value and system revenues.

f. CEC

CEC supports the Commission's proposals regarding transmission. It seeks clarification of how long-term contracts will be treated.

g. Cogenerators

CCC and CSC urge the Commission to retain cogenerators' priority ahead of UEGs, not just within the various services but in all cases. CSC also suggests that the Commission retain pricing parity by basing transmission rates on the weighted average of the services elected by the UEG. CCC and CSC believe the 5% price differential between firm transmission and core subscription transmission services does not reflect the difference in value or cost of those two services and should be increased. Finally, CSC states the Commission should preserve existing priority assignments which are the subjects of long-term contracts.

CCC objects to provisions of the Settlement because it does not adequately address cogenerator parity. It also comments that the Service Levels set forth in the Settlement should be priced differently to reflect their relative value.

On behalf of cogenerators, Oryx also comments that by changing the priority system without benefit of hearings, the proposed rules violate Public Utilities (PU) Code § 2771, which states that priority shall be set according to the public benefits conferred by various customer groups. Related to this, Oryx states that the rules change end use priorities in violation of Section 454.7 which provides that cogeneration projects shall have the highest possible priority for the purchase of natural gas. According to Oryx, the problem is especially critical for cogeneration customers with long-term contracts because they would have to pay a disproportionately large premium over present contract rates to obtain firm service.

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

Indicated Producers argues that the Commission should abandon its plan to develop firm and interruptible services now, and instead proceed to develop a capacity brokering program. It believes the Settlement's transportation scheme would be impossible to "coordinate" with a capacity brokering scheme because it resolves all issues of pricing, priority, and the means of access, leaving nothing for a capacity brokering program.

Indicated Producers objects to the substantial changes in rate design anticipated by the Settlement and suggests the issues should be the subject of hearings in I.86-06-005.

Similarly, it objects to the Settlement's provision which would prohibit changes to regulatory incentives until 1994.

Indicated Producers states the Commission does not have jurisdiction to require the utilities to offer firm service on interstate pipelines. Indicated Producers opposes the proposed rules and the Settlement on this basis and because they do not provide equivalent service for producers, marketers, and brokers. Phillips makes similar comments. Phillips also believes rates for firm service should be negotiable. It opposes the Settlement on the basis that it would perpetuate PG&E's hold on Canadian gas supplies, may permit overrecovery of costs by the utilities, and may not be consistent with federal law regarding interstate pipeline access.

Capitol opposes the Settlement on the grounds that it fails to fulfill the Commission's objectives of promoting increased competition in gas markets.

Salmon comments that the utilities should not be able to use capacity to serve the core on a least-cost basis because noncore customers will never receive any reliable transmission service under that scenario.

Hadson generally supports the proposed rules but recommends that customers be required to designate their suppliers in order to confirm nominations and permit easy communication between parties.

Enron opposes the preferential access of core customers to least-cost supply basins because the policy would promote core subscription and would not permit noncore customers to commit to any specific supply sources. It suggests pro rata access to supply basins.

CGPA generally supports the proposed rules but states the Commission should assure that the utilities do not overcollect revenues with the introduction of a new transmission rate structure.

Pan Alberta comments that the Commission's final rules should not undermine prebuild contracts with Canadian gas suppliers and supports the Settlement's terms over those proposed in D.90-07-065.

Bonus opposes the rules to implement firm and interruptible services until the regulated utilities role in noncore gas procurement is eliminated. It suggests resolving transmission issues in the capacity brokering proceeding. Bonus also opposes any restrictions on access to PGT capacity.

Mobil supports the firm and interruptible service designations but is concerned that the Commission would require FERC authority to implement the services. It also proposes that the firm rate be set at the existing default rate in recognition that the default rate includes an allocation of fixed costs that should not be imposed on interruptible customers. Finally, Mobil believes that allocations of firm capacity should not be based on historical demand alone, especially considering that some facilities switch to gas for environmental reasons.

Sunpacific recommends the Commission prohibit "bumping" of long standing noncore transactions for short-term core needs and suggests an ongoing review of further rate and service unbundling. Sunpacific generally supports the proposed treatment of A&S gas but suggests that the requirement to purchase gas from A&S producers be limited to the first year after the issuance of the final rules. Sunpacific opposes elements of the Settlement which would provide additional cost and revenue protections to the utilities by way of balancing accounts. It believes these provisions are contrary to the Commission's stated intent to promote improved performance.

NGC generally supports the rules for transportation proposed by the Commission and objects to the Settlement rules because they would not be replaced by a true capacity brokering program. CGM believes the proposals in D.90-07-065 and in the

Settlement are improvements over the existing rules but urges the Commission to move forward with capacity brokering.

i. Pipeline Companies

Transwestern argues the Commission should refrain from implementing its new rules until it has adopted capacity brokering regulations in order to assure consistency and because the reliability of noncore sales cannot be assured until a brokering program is in place.

El Paso generally supports the proposed rules but seeks clarification on how much capacity should be made available to the noncore. Kern River generally agrees with the proposed rules' treatment of transportation services except for provisions requiring noncore customers who want to use PGT to buy gas from A&GS.

j. UEG and Wholesale Customers

SDG&E is concerned with the effect of limiting utility gas sales to the noncore customers on its system. Under the present system, eight have self-procured, and the remainder prefer the administrative ease of utility service. SD&G&E states that its noncore customers already enjoy non-discriminatory access to producers and brokers, and would likely pay more for gas under the rules proposed in D.90-07-065 and the Settlement. SDG&E advocates allowing commodity sales out of a single portfolio, differentiating between service reliability levels with transportation rates and other contractual obligations such as take-or-pay.

SDG&E points out that the Commission has not been presented with an allegation of discriminatory treatment on the part of SDG&E in placing its UEG nominations with SoCal or an interstate pipeline in a manner that forecloses other noncore customers' supply options.

Edison generally supports the proposed rules creating a firm transportation service but asks the Commission to address treatment of long-term contracts. It also believes the proposed rules regarding take-or-pay forgiveness provisions are too restrictive, suggesting forgiveness for any force majeure event. It supports the Settlement provision which would eliminate demand charges with the introduction of take-or-pay obligations. Edison believes hearings are required to address the interim pricing for firm and interruptible services.

Edison suggests that if firm transportation customers are curtailed, their rate should be reduced to the interruptible rate during the period of curtailment. It also recommends curtailments within Service Levels 4 and 5 of the Settlement be implemented on a pro rata basis instead of using end-use priorities.

Southwest argues the use-or-pay provision for firm transportation should be at least as rigorous as that for core subscription and suggests a level of 85% for firm transportation.

Southwest, Palo Alto and Long Beach argue that the Commission's final rules should recognize that wholesale customers have core customers to serve and grant them the same priority as other core customers and the same rights of access to pipeline receipt points.

Long Beach also seeks clarification on how Long Beach noncore customers would qualify for firm service and the cost of that service to Long Beach.

Long Beach and SCUPP oppose the introduction of firm transportation service and favor moving forward with capacity brokering. It argues the Commission cannot revise the existing priority scheme without a hearing and without considering of existing statutes. It believes, moreover, that the firm rate should be increased to equal the core subscription rate and that revenues in excess of the existing default rate should be credited to reduce other transportation rates. Finally, it argues that the one-year, and 50% use-or-pay obligation, is too lenient.

In response to the concerns of cogenerators that all cogenerators should be given priority ahead of UEGs, SDG&E argues that this would represent an additional unwarranted subsidy for qualifying facilities (QF).

k. Industrial Customers

CIG is critical of the proposed rules' provisions for core priority, believing they would prevent noncore customers from gaining access to competitively priced gas supplies on a long-term basis. CIG agrees that the core should have highest priority but believes the rules as proposed would provide the utilities a substantial advantage in marketing core subscription service, perpetuating the existing problems with core elect. CIG supports the Settlement provisions for allocating capacity between the core and noncore.

CIG argues that demand charges would not be appropriate for interruptible customers because of the diminished quality of service. Moreover, according to CIG, the take-or-pay provisions of the proposed rules create revenue stability for the utilities, thereby eliminating the need for demand charges.

Oryx comments that, while supporting the proposed rules, it is concerned that the changes to transportation services may reduce the value of long-term contracts between the utilities and EOR customers. It reminds the Commission of its stated commitment to "allow the parties the benefit of their mutual bargain without further regulatory interference." (D.86-12-009, page 64) Oryx argues that the proposed rules would change the priority system and undermine the benefit of the discounted rates in the existing contracts.

Barry seeks clarification on the status of long-term interruptible contracts and urges the Commission to permit interruptible customers with long-term contracts to switch to firm transportation.

CAPA believes core and noncore customers should have equal access to low cost gas supply regions.

SPURR recommends that core transportation-only customers be provided the highest priority for transmission along with core sales customers.

Borax expresses concern about how rule changes might affect existing long-term transportation contracts. Borax cites language from one of the Commission's early transportation decisions which establishes that:

"It is our intention that transportation arrangements made in reliance on this decision not be nullified by future actions. Although it is likely that the program will be modified, such <u>later modifications will not affect the terms and conditions</u> or the validity and enforceability of contracts negotiated prior to the effective date of the modification." (Emphasis added.) (D.85-12-102, p. 37.)

Borax objects to the Settlement's treatment of long-term contracts because it would alter the terms of existing contracts, increasing rates or changing priority status. It also objects to take-or-pay obligations.

1. <u>DGS</u>

DGS asks how customers will know if they are going to be given access to firm interstate pipeline capacity in order to make a reasoned decision regarding level of services, and how contract customers going to be treated. DGS recommends using historical demand to allocate firm capacity. It also recommends that the Commission permit negotiated interruptible rates.

DGS argues that take-or-pay penalties should be waived for most circumstances which reduce demand except fuel switching or switching from firm to interruptible transmission service.

m. State of New Mexico

The State of New Mexico urges the Commission to move forward in the capacity brokering proceeding. It also opposes the Settlement's provisions on the grounds that it would allow the utilities to offer a higher priority transportation service than may be offered by alternative gas suppliers in tho same markets and states that the brokering fee discriminates in favor of core subscription.

2. Discussion

In general, the Settlement's proposals for transportation services are reasonable, with some exceptions we will discuss below. Our decision today does not signal our abandonment of capacity brokering. We still intend to move forward with developing FERC-approved capacity brokering programs as soon as possible.

a. Service Levels

We will adopt the service levels and pricing provisions proposed by the Settlement. We agree with the Settlement parties that it is sensible to add a surcharge to firm service which would offset rates for interruptible services. This allocation mechanism will reflect customer value reasonably well, at least until we have developed a capacity brokering program.

Therefore, we will direct the utilities to set the rate for the highest level of noncore service at the default rate plus 12 cents per decatherm. The revenues from the 12 cent surcharge will be credited to the interruptible services. We will review the level of rates at the first opportunity, whether in I.86-06-005 or individual utility cost allocation proceedings.

We will not, as the Settlement parties suggest, assume that the transportation services adopted today will remain in place after a capacity brokering program is in place. We cannot anticipate by the record in this proceeding how the Settlement's provisions would dovetail with final brokering rules or the effects the new service levels may have on capacity brokering programs. Moreover, the reliability of "firm" service adopted today is unclear because noncore customers must rely on utilities' "best efforts" to purchase identified gas supplies. A FERC-approved capacity brokering program will operate better to promote competition, and assure noncore customers get the level of reliability they pay for. The new transportation services will be interim pending final resolution of capacity brokering; however, we encourage parties to propose ways to integrate the interim rules with a permanent capacity brokering program.

As discussed previously, we will provide that core subscription customers receive the same level of service as the highest level of noncore transportation service, rather than at a higher level as the proposed rules would have required. We recognize that noncore transportation customers may not otherwise receive reliable transmission service. We also modify use-or-pay obligations to require imposition of penalties where commitments are not met for any reason except force majeure conditions, as we discussed in Section IV.B. on core subscription.

SDG&E makes a case for separate treatment of its noncore, non-UEG with respect to utility procurement services. Its noncore customers may not receive the pricing benefits anticipated for other utilities' noncore classes. SDG&E noncore customers have not complained of discriminatory treatment, as have PG&E and SoCal noncore customers. We will allow SDG&E to procure gas for their noncore, non-UEG customers with transportation service levels. SDG&E noncore customers receiving transportation service at Levels 2 through 5 must, in order to purchase gas, commit to the same procurement take-or-pay requirements as core subscription customers.

The Settlement asks us to determine how curtailments would occur for Service Levels 4 and 5. We will allow pro rata curtailment for those service levels except that customers will first be curtailed according to the level of payment they make. That is, in those services levels where negotiated rates are permitted, customers paying the lowest volumetric rate for transport service will be curtailed first. We discuss our treatment of cogenerator volumes below.

On the subject of pipeline capacity, the Settlement's provisions are reasonable which allocate SoCal's use of El Paso and Transwestern capacity between the core and noncore on a pro rata basis. For PG&E, the Settlement reserves for 450 MMcf per day of capacity for noncore customer use, 250 MMcf per day of which would be on the PGT line, and 200 MMcf a day on El Paso. We are concerned that this provision does not go far enough to open up access to Canadian supplies. However, in the context of other Settlement provisions, discussed in other portions of this decision, we believe this compromise will make some modest progress toward a more competitive Canadian gas market with attendant benefits for core and noncore customers.

Our final rules for transportation service are as follows:

> After taking into account system supply gas from California production, Pacific Offshore Pipeline Company and Pacific Interstate Offshore Company, SoCal shall reserve for system supply purposes sufficient interstate pipeline capacity on the El Paso and Transwestern systems (1) to serve "cold year" requirements of core (P-1 and P-2A) customers, and (2) to provide a reasonable allowance for company use and lost and unaccounted for (LUAF) gas. The calculation of the amount of capacity to be reserved for the core market shall also take into account the capacity needed to have sufficient gas in storage to serve core peak day and cold year winter season requirements. The total capacity allocated to the service of P-1 and P-2A customers on El Paso and Transwestern need not be the same each month. SoCal may adjust the amount of capacity reserved for the core

market consistent with these rules no more than once a year.

Interstate pipeline capacity will be reserved by SoCal for the core market on a pro rata basis between El Paso Natural Gas Company and Transwestern Pipeline Company. The pro rata amount will be computed as a ratio of SoCal's capacity rights on an individual pipeline to SoCal's total capacity rights on both pipelines. Capacity reserved for the core market on El Paso and Transwestern will be reserved on a pro rata basis divided at each of the "constraint" points on each of the two pipeline companies to the extent permitted and feasible under their tariffs and FERC regulations. These rules do not modify the terms of the long-term contract between SoCal and SDG&E which was approved by the Commission in Resolution G-2921.

The SoCal contract with SDG&E shall be subject to the outcome of further proceedings in the capacity brokering case with respect to the integration of long-term contracts into the firm transportation program set forth in these rules.

Pacific Gas and Electric Company (PG&E) shall make available to noncore transportation customers 450 MMcf per day of its pipeline capacity. Of this 450 MMcf per day, 250 MMcf per day shall be over PG&E's Pacific Gas Transmission (PGT) line to Canada and 200 MMcf per day over El Paso.

Pursuant to Resolution G-2921, the Commission has approved the assignment of firm interstate pipeline capacity and storage rights by SoCal to SDG&E. Implementation of these provisions remains subject to the tariffs and regulations applicable to the interstate pipeline systems. Upon implementation of the provisions of the SoCal/SDG&E contract and Resolution G-2921, SDG&E's noncore customers will have pro rata access to such rights.

SDG&E may procure gas for its noncore, non-UEG customers with transportation service at all levels. SDG&E's noncore, non-UEG customers receiving transportation service at levels 2 through 5 must, in order to purchase gas from SDG&E, commit to the same obligations as core subscription customers.

The utilities shall make available five levels of transportation service:

Service Level 1 -- core service. All capacity reserved for any customer is recallable to preserve Service Level 1 transportation access for core customers.

Service Level 2 -- firm service for noncore customers under an annual contract with a 75% use-or-pay obligation and a use-or-pay penalty equal to 80% of the firm transportation rate applicable to the customers. This service shall require a two-year commitment. Core subscription service includes Service Level 2 transportation. The transport rate is not negotiable.

Service Level 3 -- interruptible service under an annual contract with a 75% use-or-pay obligation and a use-or-pay obligation penalty equal to 60% of the customer's applicable transportation rate. The utility and the customer may negotiate rates for Service Level 3.

Service Level 4 -- interruptible service under a monthly contract subject to a 75% use-or-pay obligation and a use-or-pay penalty equal to 30% of the customer's applicable transportation rate. The utility and the customer may negotiate rates for Service Level 4.

Service Level 5 -- interruptible service for nomination periods of less than a full month with no use-or-pay obligation. The utility and the customer may negotiate rates for Service Level 5.

Noncore customers shall be permitted to split their requirements among noncore Service Levels. Where the service level requires an annual contract commitment, the customers will nominate quantities consistent with their historic requirements or, otherwise, will be required to demonstrate the basis for such quantities. In lieu of a stated annual contact quantity, a noncore customer also may select "full requirements" service under Service Level 2. A "full requirements" customer is prohibited from using alternate fuels (except in the event of curtailment, to test alternate fuel systems or where the utility has expressly authorized use of alternate fuels). To the extent that a full requirements customer uses alternate fuels for other reasons, the customer shall be subject to a use-or-pay penalty equal to 80% of its applicable firm transportation rate.

The coordination of full requirements customers needs with the nomination of stated contract quantities for firm transportation shall be addressed in the tariff implementation workshops in R.90-02-008.

For monthly service (Service Level 4), the customers's Maximum Daily Quantity (MDQ) will be equal to his contract quantity for the month expressed in MDth per day. For service under annual contracts (Service Levels 2 and 3) the utility shall negotiate an MDQ that is consistent with the expected monthly demand profile of the customer. The customer's average MDQ over the year will have to exceed the annual contract quantity in order to account for daily and monthly fluctuations in gas usage. Implementation of the MDQ procedure shall be addressed in the tariff implementation workshops in R.90-02-008.

Until an integrated interstate-intrastate capacity brokering program is adopted, the utilities will use their capacity rights to purchase gas supplies identified by individual customers on a non-discriminatory "best efforts" basis, and resell the gas to the customer. Alternatives to this arrangement, if required, shall be submitted to the Commission in a petition for modification. Service Level 2 is "firm" at the burnor tip until an integrated interstate-intrastate capacity brokering program is adopted.

Initial allocation of Service Level 2 capacity shall be based on customers' pro rata share of nominations where customers' nominations in total exceed available capacity. The utilities may confirm the reasonableness of customers' nominations by reviewing historical demand and other circumstances, including operational changes designed to accommodate air quality regulations or objectives.

Use-or-pay penalties for transportation services shall be forgiven to the extent the customer's usage falls below the use-or-pay level due to service interruptions imposed by the utility or upstream pipeline or force majeure conditions, excluding required maintenance of customer's facilities, plant closures, economic conditions or variations in agricultural crop production.

Curtailments for Levels 2 and 3 shall be according to existing end use priorities. For Levels 4 and 5, the utility shall curtail customers according to the level of payment they make for service, with highest paying customers to be curtailed last. For customers who pay the same rates, the utilities shall curtail customers on a pro rata basis.

Each utility shall file with the Commission Advisory and Compliance Division estimated capacity allocation between transportation service levels on each interstate pipeline.

The filing shall be made no later than the deadline for noncore customers to make their annual and biannual service choices.

b. <u>Demand Charges</u>

The Settlement's provision for eliminating demand charges is, for noncore customers, an essential element of their bargain. We are uncomfortable, however, eliminating demand charges without first considering the potential effects on economic efficiency and customer behavior.

We adopted demand charges in large part as a way to reflect the costs imposed on the gas supply system by uneven demand. Specifically, demand charges are intended to allocate costs to customers that create a demand for additional storage and pipeline capacity generally because those customers' supply requirements are seasonal. In this way, demand charges are consistent with our policy of developing rate structures which reflect costs. Volumetric rates which do not vary between peak demand periods and periods of lesser demand do not reflect the costs of capacity.

The Settlement parties believe demand charges are unpredictable and unnecessary as a means of providing revenue stability for utilities with the adoption of use-or-pay charges. We will adopt the Settlement's proposal to eliminate demand charges in favor of volumetric rates but do so with the condition that before doing so we will review rate design alternatives that are consistent with our policy of moving further in the direction of cost-based rates. We are particularly interested in considering seasonally-differentiated volumetric rates. We will review such rate design proposals in I.86-06-005, in which we are currently reviewing rate design and cost allocation issues more generally. We intend to issue a decision on this rate design matter before full implementation of the program adopted today.

c. Balancing Accounts and Incentives

D.90-07-065 stated we would consider utility regulatory incentives along a separate path from rules regarding utility procurement and transportation. We expressed interest in several options and sought comments from the parties, which were filed September 17, 1990.

The Settlement dispenses with any review of incentives until 1994. It also establishes balancing accounts for several aspects of the new program. Balancing accounts would be established for all transportation revenues (with a 25% shareholder liability for noncore transportation), transportation forecasting errors, unspecified administrative expenses of the program, brokerage fees, and any liabilities PG&E might incur in connection with revisiting its PGT transmission access rights as a result of Settlement provisions.

We believe these various balancing accounts, in addition to those already in existence, are not justified by the Settlement parties and may transfer new risk to utility ratepayers with few offsetting benefits. We will authorize the implementation of the noncore transportation balancing account as proposed by the Settlement on the basis that a two-year cost allocation proceeding may otherwise increase utility risk.

We will not, however, adopt a balancing account for unspecified administrative expenses associated with the program. Regulatory changes are a normal part of utility operations. Utilities recover in base rates revenues for regulatory expenses and we are not convinced that the program changes we adopt today will present abnormally high costs of implementation. Nor will we adopt balancing accounts for brokerage fees. The utilities have had brokerage fees set in ACAPs after substantial review. We believe the existing ratemaking treatment of brokerage fees is adequate. We address in Section IV.D. the Settlement's proposal for allocating PG&E's A&S costs.

We would not under any circumstances agree to forego regulatory review of incentives for any specified time. We adopt certain incentives in this decision but may continue a review of incentives after a more thorough review of the comments filed on September 17, 1990 in this proceeding.

We add the following to our rules for transportation services:

> The utilities shall enter into balancing accounts revenues associated with noncore transportation services and shall recover in biannual cost allocation proceedings 75% of the difference between forecasted revenues and actual revenues from noncore transportation services. Utility shareholders shall be liable for 25% of the difference between forecasted revenues and actual revenues from noncore transportation services.

d. Cogeneration Parity

Cogenerators urge the Commission to preserve the existing rules on parity for them over UEG customers by making clear that all UEG volumes would be curtailed before any cogenerator volumes. They cite Sections 454.4 and 454.7. Section 454.4 states in pertinent part:

> "The commission shall establish rates for gas which is utilized in cogeneration technology projects not higher than the rates established for gas utilitized as a fuel by an electric plant in the generation of electricity..."

Section 454.7 states

> "The commission shall, to the extent permitted by federal law and consistent with Section 2771, provide cogeneration technology projects with the highest possible priority for the purchase of natural gas."

We have consistently recognized the importance of cogenerators in providing the state with an efficient source of energy and do not intend to change our policy now. Moreover, the transportation services we establish today will not violate the intent or plain meaning of Section 454.4.

The PU Code does not require that all cogenerator gas rates be lower than all UEG rates. Consistent with Section 454.4, cogenerators pay the lower of the UEG rate or the otherwise applicable rate for energy production which is at least as efficient as UEG production. That rate design policy will not change.

With regard to Section 454.7, the Commission is only required to provide cogenerators with the highest priority service to the extent they provide the "most public benefits" and serve "the greatest public need," as set forth in Section 2771. We do not need to restate here the important public benefits associated with cogeneration technologies. We will continue to consider those benefits in determining priorities between UEGs and cogenerators. An efficient use of scarce resources, however, requires that customers with supply options be served according to the value they place on those resources. It is therefore reasonable that UEG volumes may in some cases receive priority ahead of cogenerators' volumes where UEGs pay more for that same service. On the other hand, where UEGs and cogenerators pay an equal sum, cogenerators will always receive priority ahead of UEGs, consistent with our policy and the Code. We will not adopt CCC's suggestion to require that cogenerators receive curtailment priority over UEGs in cases where the UEG is paying a higher rate than cogenerators. That would be inconsistent with the intent of the PU Code and with prudent regulatory policy.

We will adopt the following rule for treatment of cogenerator transportation priority:

> For Service Levels 2 and 3, UEG customers shall be curtailed ahead of cogeneration

> customers where the UEG customer pays an equal or lower rate. In Service Levels 4 and 5, where the UEG customer pays more than the cogeneration customer, the cogeneration customer shall be curtailed ahead of the UEG customer.

e. Existing Long-Term Contracts with Noncore Customers

As several parties have commented, SoCal and PG&E already have certain contractual obligations to provide transportation. Customers under those contracts naturally do not wish to have their contract rights abridged under the terms of any new program. As Oryx and Borax point out, they have relied on Commission assurances that program changes would not change the terms or conditions of existing contracts.

We do not intend to retract our promise to honor transportation contracts, which are primarily with EOR customers. Our rules will not require changes to existing contracts. That does not mean, however, that regulation and the terms and conditions of existing utility tariffs and other rules cannot change during the term of existing contracts. In fact, we have made the parties aware on several occasions that our gas policies may change as circumstances change. D.86-12-010, for example, stated "if transmission capacity becomes constrained in the future, our adopted priority system for noncore customers should result in an economically efficient allocation of scarce capacity." More to the point, D.86-12-009 stated "In the longer term, EOR customers may have to pay rates above variable transmission cost in order to assure the same high level of reliability that exists today." These statements, issued before the EOR contracts were signed, made clear that priority for transportation services could change so as to require different pricing policies. We hardly need add that California is currently in a position of constrained pipeline capacity, thus warranting the changes we make by this order.

The program we adopt today recognizes changed circumstances and provides for service priorities according to the commitments customers make in terms of demand, time periods, and rate levels. Tariffs will change and customers may pay more or less for service. These changes in regulation, rate design, and service conditions are designed to respond to changing circumstances and needed improvements in our regulatory program. Regulatory change is a risk that all parties face, including those who sign long-term contracts. We would be ignoring our obligations if we forestalled required regulatory changes on the basis that a handful of customers have signed long-term contracts that might be affected.

We reiterate that today's program will not change contract terms and conditions. To the extent that long-term contracts are tied to utility tariffed rates and conditions, contracting customers must, however, assume responsibility for those changes unless their contracts provide otherwise. For example, if a contract provides for changes in a stated base transportation rate according to predetermined escalation factors, the rates will continue to change accordingly, notwithstanding tariffed rate changes. If, on the other hand, contract rates are tied to tariffed rates, the payments made by the customer would change.

We believe the Settlement adopted today provides favorable treatment of existing EOR transportation contracts that are the subject of D.85-12-102. The Settlement would permit contract customers to opt for Service Level 3, which is a high level of service, at their contract rates. Alternatively, contract customers may opt for a discounted Service Level 2 firm transportation service for the remaining contract terms at a rate equal to halfway between the current contract rate and halfway between the otherwise applicable default rate plus the 12 cent per decatherm surcharge.

We will adopt the Settlement's treatment of existing EOR cogeneration contracts:

> Customers with long-term contracts in existence on the effective date of these rules, and whose contracts do not specify otherwise, shall receive at the contract rate Service Level 3 service. Those customers may alternatively opt for Service Level 2 service at a rate to equal to one-half the existing default rate and one-half the existing contract rate, plus a 12 cent per decatherm surcharge. Express contract terms and conditions of existing contracts shall not be changed as a result of the rules herein.

f. <u>New Long-Term Contracts</u>

The Settlement appears to provide for negotiation of long-term transportation contracts with terms longer than one year. We have set forth the standards for negotiation of long-term contracts in D.89-12-045 and will continue to apply those standards until the issue is considered in the context of capacity brokering. We continue to have concerns regarding equal opportunities for customers to negotiate contracts. We must also consider the FERC's policy to provide equal opportunities for parties to obtain long-term access to interstate capacity. With the availability of additional pipeline capacity and the development of capacity brokering programs, the prospects for long-term agreements will improve and reliability problems alleviated. We specify the following guidance for new long-term contracts:

> Nothing in these rules shall be construed to amend the Commission's existing policy regarding long-term contracts for pipeline capacity, set forth in D.89-12-045, until and unless the Commission sets forth new policy as part of capacity brokering programs.

To address the concerns of parties seeking long-term transportation contracts, we shall expedite the capacity brokering proceeding in which the issue of such contracts and their relationship to capacity brokering has already been raised.

D. PG&E's Canadian Contracts

D.90-7-065 imposed the requirement that noncore customers' purchases over PGT be made from A&S in recognition of contract obligations which cannot be abandoned in the immediate future. We expressed criticism of PG&E for failing to develop more flexible contract relationships over a period of time during which we have stated our intent to move toward competition in all gas markets.

Because PG&E has entered into contract obligations which preclude competitive access to bottleneck facilities, and because of our desire to ensure that all gas is priced by a workably competitive market, we stated our view that the A&S contracts should be renegotiated by December 31, 1991. We also stated that the price PG&E pays for all its gas, including Canadian gas will be subject to scrutiny in PG&E's next reasonableness review.

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

Our proposed rules regarding purchases of Canadian gas and PG&E's treatment of Canadian gas contracts are as follows:

> 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.

1. Positions of the Parties

a. PG&E

On the subject of the FERC order regarding PGT minimum takes, PG&E replies that it now pays a tariffed rate rather than the contract rate in its contract with PGT. It emphasizes that the FERC order did not change the obligations of A&S to Canadian suppliers, the contract between A&S and PGT, or the service agreement between PGT and PG&E.

In general PG&E believes any "problem" with the Canadian gas supply system arises because of changes in the market environment and in what the Commission perceives to be an appropriate market structure. PG&E states it is prepared to promote changes to its contractual relationships depending upon the outcome of this proceeding, but the arbitrary December 31, 1991 date is not workable.

PG&E argues that allocating contract costs to PG&E's shareholders is unreasonable for several reasons. First, PG&E points to Commission statements regarding the benefits of the core elect and its support of the A&S export license extension at the Canadian National Energy Board. It states that ratepayers, not shareholders, have benefited from the costs savings available from A&S' contracts for Canadian gas and PG&E shareholders have not gained from the contract obligations. Finally PG&E believes that if the A&S contracts are found not to be reasonable, it will be because of changes in industry structure mandated by the Commission. PG&E believes the contracts are reasonable in the context of existing policy. PG&E cites several occasions upon which it has negotiated amendments to the A&S agreements which responded to market changes.

PG&E agrees with the Commission that Canadian gas prices to California may fall if there were more buyers and sellers competing for such supply. According to PG&E, however, barriers to such a scenario must be overcome first. Among the prerequisites for increased competition are the addition of new pipeline and the willingness of the Canadian government to issue short-term export permits.

b. Settlement

As stated in Section IV.C. on noncore transportation services, PG&E would, under the terms of the Settlement, make 250 MMcf per day of capacity available on PGT. Noncore customers would be permitted to negotiate their own gas supply arrangements only with producers currently under contract to A&S. Once a noncore customer has made such an agreement with an A&S producer, PG&E would arrange to have the gas purchases by A&S under existing gas purchase agreements. In return, A&S producers would credit all volumes taken under this mechanism against any A&S contractual commitments. This arrangement would be in effect until August 1, 1994, after which time PG&E's noncore customers would be able to purchase gas from any Canadian supplier, presumably as a result of PSG efforts to renegotiate its contracts.

To the extent that PG&E reasonably incurs any costs as a result of implementing this Settlement provision, such costs would be allocated to all ratepayers.

c. DRA

DRA expresses disappointment over the Commission's proposed treatment of PG&E's Canadian gas contracts. According to DRA, PG&E is not obligated to buy any gas from PGT under the provisions of a recent FERC order (Pacific Gas Transmission Company, 50 FERC 61,067). DRA comments that PG&E is not under contract with A&S to purchase its gas supplies and that noncore customers should therefore be permitted to purchase gas from any source. Without this activity, the Canadian gas markets will not become more competitive, according to DRA.

DRA believes the A&S producers' recent rejection of the A&S proposal to base the Tier II price on an Alberta market price indicates an unwillingness to move toward a more competitive market even on a gradual basis, warranting more aggressive action. DRA quotes a Commission resolution which, four years ago, emphasizing the importance of PG&E providing Canadian producers with access to the California market:

> "It is important that all producers have fair and equal access to the California market. We emphasize the need of Canadian producers, especially those not associated with A&S (Alberta & Southern, PG&E's Canadian gas acquisition subsidiary), to have access to the California market. PG&E has advised the Commission that its filing for Section 436 open access transportation authority is imminent. We anticipate that when open access is provided over the PGT line, greater competition from Canadian producers will result in lowered gas prices to the state's gas ratepayers." (CPUC, Resolution G-2704, November 14, 1986, pp. 8-9.)

DRA argues that PG&E can influence whether A&S eliminates its minimum commodity bill, a view that is supported by the FERC. It is time for the Commission to put pressure on PG&E to do so, according to DRA.

DRA also objects to the Settlement's provisions which, according to DRA, appear to insulate PG&E and A&S from all risk associated with the A&S contracts and any other related costs during a three year transition period.

d. <u>Canadian Government Agencies</u>

The Government of Canada states the provisions in D.90-07-065 may undermine the long-term contractual relationships between Canada and California and argues the Commission should not unilaterally change those relationships.

The Ministry believes the proposed rules regarding Canadian contracts may lead to a view by Canadian producers that the California market is not reliable and thereby reduce production in the future. The Ministry also states that A&S will be subject to take-or-pay penalties if volumes fall, penalties which will be ultimately passed along to PG&E's ratepayers. Tho Ministry believes that the best way to promote competition is to construct an additional pipeline from Canada to California.

APMC's comments are similar to thoso made by the Ministry and the Government of Canada.

e. <u>CEC</u>

The CEC also supports the Commission's efforts to encourage PG&E to be more competitive in its procurement of Canadian gas, and suggests the Commission should closely monitor PG&E's Canadian gas procurement practices over the next few years to see if additional measures are required.

f. <u>Independent Gas Producers and Brokers</u>

Salmon believes the Commission errs in assuming that the contracts between Canadian producers and A&S can be unilaterally renegotiated.

CPG argues that the Commission's directive to renegotiate the A&S contracts is unlawful in part because the it represents a "collateral attack" on federal orders approving the import contract. It would also violate the Federal Trade Agreement which requires California to treat A&S contracts on terms equal to the most favorable treatment accorded to other gas supplies, according to CPG.

CPG also argues that the Commission directs the utilities to implement unlawful transmission arrangements by establishing firm and interruptible services under "buy-sell" agreements which, according to CPG, are a "blatant intrusion upon an area reserved to the FERC's exclusive jurisdiction." Finally, CPG believes all these issues must be subject to hearings in order to satisfy the fundamental precepts of due process.

The comments of IPAC and CPA are similar to those made by CPG and suggest the Commission has improperly directed one of its jurisdictional utilities to abrogate contracts.

g. Industrial Customers

CIG does not believe the proposed rules adequately address treatment of PG&E's Canadian supplies. CIG supports the Settlement's approach, which would allow A&S producers to compete among themselves for sales to noncore customers but does not require or permit A&S to be the only marketing agent for its producers.

2. Discussion

We have already discussed the level of PGT capacity PG&E will make available to noncore customers. We turn here to the issue of contracts between Canadian producers and PG&E's affiliate, specifically, liability for outstanding contractual obligations and purchases of Canadian gas by noncore customers.

Contrary to any impression D.90-07-065 may have left, we do not intend that the contracts between A&S and Canadian producers be unilaterally abrogated. In fact, we cannot require A&S to abandon contracts because A&S is not within our jurisdiction. PG&E is subject to our jurisdiction but is not a party to the contracts.

Notwithstanding the comments of Canadian producers regarding honoring long-term agreements and our intent to leave it to the parties to act according to their own best interests, gas supply contracts are not cast in stone. As an example, supply terms in Canadian gas contracts have been renegotiated on more than one occasion and the price terms are annually renegotiated. All contracting parties may benefit when contracts are renegotiated to reflect changed market conditions.

PG&E is not bound by the contracts between A&S and Canadian producers, and we may require its shareholders to assume liability for gas costs or terms of service which are unreasonable just as all utilities are held liable for unreasonable fuel costs. We are also within our authority to take action against PG&E for its monopolization of the PGT line, which is contrary to policy statements we have made and which may have kept Canadian gas prices high, as we have said.

None of the foregoing should surprise any party with even casual acquaintance with past Commission policies and practices.

Because of our view that all PG&E's gas supply contracts, including those with PGT and A&S, should be subject to reasonableness review, we will not permit PG&E to allocate automatically to all ratepayers unspecified costs incurred "as a necessary result" of the Settlement, as the Settlement proposes. We have consistently argued against guaranteed recovery of contract costs arising from unmet contract obligations in FERC proceedings. It would be unfair and unwise for us to pass through such costs to ratepayers without further review.

Moreover, the Settlement's provisions for access to PGT are minimal. Its requirement that noncore customers buy gas from A&S suppliers further eases PG&E's outstanding contractual liability compared to other options available to us. In consideration of these provisions which protect PG&E considerably, PG&E should take the risk for any associated liabilities under its existing contracts, if, as we assume, these are the liabilities which the Settlement anticipates. PG&E may, however, propose in subsequent reasonableness reviews that ratepayers share those liabilities but it will have the burden to show that the costs it incurs are reasonable. As a matter of fairness, we will consider how the changes we adopt today, should affect allocation of PG&E's liabilities between shareholders and ratepayers, and between customer classes.

On the subject of gas purchases from Canada, the Settlement provides that noncore customers would be permitted to negotiate gas supply arrangements only with producers under contract with A&S. PG&E would arrange for A&S to purchase the gas, which would be credited against any contractual commitments between A&S and the producers.

We agree with DRA that these Settlement provisions would mitigate liability of PG&E affiliates to which ratepayers owe no particular obligation. PGT's contractual obligations to A&S are, like A&S' obligations to Canadian producers, not guaranteed by PG&E's ratepayers.

On the other hand, we seek to make the best out of a difficult set of circumstances. We cannot order PGT or A&S to make capacity available for noncore customers or to renegotiate their contracts because they are not within our jurisdiction. More important, some compromise appears necessary to maintain good trade relationships with Canada, relationships which will benefit Canadians and Californians alike. For this reason, we will adopt the Settlement provisions which would be in effect until August 1, 1994.

We note that PG&E informed the Commission, by way of a letter dated September 20 (Attached as Appendix B), that it has reached an agreement with A&S and AMPC which provides details for implementing the noncore gas purchases from A&S producers anticipated by the Settlement. The letter's provisions appear fully consistent with the Settlement provisions incorporated into the rules we adopt today. While we cannot formally adopt this supplementary agreement as it respects matters under the jurisdiction of Canadian authorities, we do applaud the agreement as an effective means to implement the rules we adopt today.

> Noncore transportation customers may transport Canadian gas over PGT subject to the following conditions. Until August 1, 1994, noncore customers may negotiate gas supply arrangements only with producers under contract with Alberta and Southern (A&S). Once a noncore customer has made such an agreement with an A&S supplier, PG&E will arrange to have the gas purchased by A&S under existing gas purchase agreements and will arrange to have the gas transported by PGT. Noncore customers may purchase gas from any Canadian supplier after August 1, 1994.

E. Treatment of UEG Departments of Combined Utilities

D.90-07-065 proposed limiting UEGs of combined utilities to subscribing to the core for more than 15% of tho average annual requirements. We stated a concern that PG&E's UEG loads dampen competition in ways which are costly to all ratepayors. Because PG&E buys gas through its affiliate, A&S, and passos 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. We also stated our concern that Canadian suppliers are not given equal opportunities to negotiate sales agreements and seek access to the California market.

We proposed 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.

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 generally be able to purchase gas from the gas department as any other customer. However, pending implementation of a capacity allocation program P-5 customers would not be permitted to nominate more than 65% of their requirements (based on most recently-adopted ACAP throughput forecasts) into Service Levels 2 and 3 in the aggregate. P-5 customers would not be eligible for "full requirements" service.

b. PG&E

PG&E believes the proposed limits on UEG gas purchases are unnecessary and unfair. It believes that lack of access to capacity, not UEG demand, is responsible for the inability of brokers, producers and customers to compete effectively. PG&E argues the Commission has recognized in past decisions the bargaining leverage and operational benefits of PG&E's procurement on behalf of its UEG.

c. DRA

DRA supports the proposed rules' treatment of UEGs of combined utilities. DRA suggests the Commission should specify that the gas procurement contracts for PG&E's gas and electric departments be negotiated as entirely separate transactions.

DRA opposes the Settlement's UEG provisions, stating that the 65% maximum core purchases is an inadequate trade-off for passing along to ratepayers the "transition costs" PG&E and A&S incur. Under the Settlement terms, according to DRA, PG&E's UEG will continue to permit the monopolization of the PGT line.

d. CEC

CEC supports the proposed rules but expresses some concern that the 15% limit could reduce the reliability of electric service for combined utilities. It suggests that the final rules offer a clear justification for the core subscription limitations on UEGs.

e. Industrial Customers

CIG does not object to the proposed rules' treatment of UEG volumes but advocates the settlement's approach.

f. UEG and Wholesale Customers

SDG&E believes limiting its UEG's purchases from its gas affiliate will reduce the bargaining leverage of the utility in purchasing gas supplies, especially considering that producers are aware that core customers do not have supply options. The proposed rules on this issue, according to SDG&E, will also affect the costs of buying gas and undermine seasonal load balancing.

SDG&E also argues that requiring a combined utility's UEG department to purchase gas separately results in additional costs to core customers and its electric customers, when no preferential transportation treatment of UEG nominated gas over other noncore gas has been alleged.

g. Pipeline Companies

Kern River generally supports the proposed rules regarding UEG purchases but suggests the limit be set at actual start-up requirements rather than 15%.

h. Independent Producers and Marketers

Phillips, Salmon and Hadson generally support the proposed rules regarding core subscription by UEGs of combined utilities. Enron believes the Commission's rules will not fulfill its objective to increase PGT access for noncore, and favors instead pro rata access.

Sunpacific opposes the Settlement terms, arguing that economies of scale in procurement do not require the consolidation of UEG and core loads. Sunpacific also believes the advantages to UEG's of purchasing core services under the terms of the Settlement provides UEGs with advantages which are not available to cogenerators contrary to Section 454.4 requiring parity between UEGs and cogenerators.

i. TURN

TURN argues the limitation on UEGs procurement options unwisely second guesses utility management's judgment. TURN argues that a better way to open up access to Canadian supplies is to set aside capacity on PGT, the approach taken by the Settlement.

TURN believes all of the Commission's objectives regarding competition for Canadian gas can be met through less drastic means and in ways which will preserve the UEG's access to low priced gas.

The Commission's proposal to limit sales to SDG&E's UEG is not based on any relay or perceived abuses by SDG&E, according to TURN. TURN recommends the authority to be automatically suspended if SDG&E merges with Edison.

j. Cogenerators

CCC and CSC restate their view that no UEG, including Edison, should be permitted to purchase any of its demand from the core subscription service.

k. State of New Mexico

The State of New Mexico generally supports the proposal to limit UEG gas purchases from the core portfolio and opposes the provisions set forth in the Settlement for UEG core purchases.

l. Producers and Marketers

Sunpacific comments that the gas buying activities of UEGs must serve the best interests of their electric ratepayers and that access to utility gas by UEGs should be equal to access provided cogenerators.

Hadson supports the proposed rules on UEG purchases from the core subscription service.

2. Discussion

We proposed limiting core subscription purchases by UEGs of combined utilities because of our concern that UEG volumes may unreasonably limit the availability of pipeline capacity to noncore customers. We are convinced after reading the comments of the parties, however, that the Settlement's proposed treatment of UEGs, in combination with other Settlement provisions, is a reasonable next step toward a more equitable and efficient gas supply system.

In considering SDG&E's request to permit unlimited commodity sales to its UEG department, we note that no allegations of abuse have been alleged to date on the SDG&E system, as has been the case for PG&E and SoCal. While we grant SDG&E's request at this time, we reserve the right to reconsider this exception if abuses are discovered. We require SDG&E to survey its larger noncore, non-UEG customers for their views on SDG&E conduct with respect to the treatment of noncore versus UEG gas transportation and report to the Commission after six months of operations under the new rules adopted today.

Although PG&E's UEG may nominate some firm capacity under the Settlement's provisions, the effects of its UEG's participation in the market are likely to be of less impact as time passes. Over the next few years, the strain on the system will be alleviated by planned capacity additions, capacity brokering, and reductions in A&S contract obligations. In the meantime, UEGs will retain access to low priced gas and will have reasonable transportation options.

We adopt the following rule for UEG purchases:

> UEGs and other end use priority P-5 customers generally shall be subject to the same terms and conditions applicable to other noncore customers except that P-5 customers shall not be permitted to nominate more than 65% of their requirements into Service Levels 2 and 3 in the aggregate. P-5 customers shall not be eligible to receive their full service requirements from utility core subscription services. These conditions may be changed according to rules adopted for capacity brokering programs.

SDG&E may procure gas for its UEG department.

F. Balancing and Standby Services

D.90-07-065 proposed rules designed to discourage the use of balancing and standby services because these services complicate utility operations and planning. We proposed a balancing tolerance of 10% of nominations with 30 days for carrying forward the balance. The proposed rules permitted trading of imbalances on the grounds that the utility operations would not be complicated or made more costly as a result.

We proposed a standby service rate equal to 150% of the core WACOG with utility purchases of overnominations be set at 50% of the core WACOG. We set price levels seeking to protect core customers from increased liabilities and encourage noncore customers to plan nominations carefully. Standby service would 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.

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

a. <u>The Settlement</u>

The Settlement provides that SoCal's transportation customers may carry over positive imbalances equal to 10 days of average usage without penalty, and negative imbalances of 2 days of average usage. If the customer's cumulative imbalance in a given month excess the tolerances, an imbalance charge would be applied. SoCal would be permitted to purchase positive imbalances for 80% of the annual WACOG or the lowest incremental cost of gas purchased by the utility in that month plus operation and maintenance costs.

Standby gas service would be priced at the higher of 120% of the annual WACOG plus brokerages fees or the highest-priced supply purchased by the utility in that month plus the brokorage fee.

PG&E's customers would be permitted 15% tolerances. Where positive imbalances exceed that amount, PG&E could purchase the extra gas for 80% of the posted monthly WACOG. Standby service will cost the higher of 120% of the posted monthly WACOG or the highest incremental cost of gas for that month plus brokerage fee.

SDG&E's customers would be permitted 10% imbalances. Where positive imbalances occur, SDG&E would have tho right to purchase the gas at the lower of 80% of the monthly WACOG or the lowest incremental cost of gas, each less an amount to compensate for operation and maintenance (as determined in SDG&E's ACAP proceeding). SDG&E would provide standby service at the higher of 120% of the monthly WACOG or the incremental cost of gas for that month plus the applicable brokerage fee.

Customers of all three utilities would be permitted to trade imbalances, and each utility would be obligated to provide a service to exchange offers by customers.

b. PG&E

PG&E supports restrictive balancing and standby provisions and argues the 10% tolerance is too high. It also suggests that the thirty-day make-up period will permit customers to, for example, deliver no gas in one month and make-up the entire imbalance the following month. Customers could also true-up imbalances by creating additional, planned imbalances in the opposite direction during subsequent months. PG&E suggests such circumstances could be costly and administratively complex for the utilities. It supports the pricing proposals for standby services and purchases of positive imbalances.

c. <u>SoCal</u>

SoCal believes the proposed rules for balancing and standby services are too restrictive. It supports the Settlement's approach, which is permissive for overdeliveries but more restrictive for underdeliveries in order to recognize the Commission's goal of limiting utility gas sales to noncore customers.

SoCal urges the Commission to eliminate the notice requirement before charging because of its cost and the difficulty of monitoring customers' efforts at getting back in balance.

d. <u>DRA</u>

DRA maintains that noncore customers should be within the 10% imbalance at the end of each month, rather than with a 30-day make-up period proposed by the rules, or they should pay for standby service. DRA also recommends that the rate for standby service by set at 150% of the core WACOG or the incremental cost of gas in the month, whichever is greater, to reflect the cost of incremental gas during winter months. DRA comments that trading of imbalances is acceptable as long as the utilities are not required to administer the trades.

DRA objects to the inconsistent treatment of balancing and standby services between the utilities proposed in the Settlement. It believes SoCal's 30% tolerance level will effectively replace demand for storage banking and is unclear how SoCal could operate under such rules given the high number of curtailments it has imposed in recent years. DRA objects to the provision in the Settlement which would require the utilities to administer a trading system, commenting that the program could be expensive and would be better administered by other market participants.

e. <u>TURN</u>

TURN does not object to the proposed rules on balancing and standby services but recommends that the standby rate should be referenced to the actual monthly WACOG, rather than an adopted annual figure because the proposed standby rate may not be compensatory during the winter months.

f. <u>CEC</u>

CEC supports the proposed rules on balancing and standby services.

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

Edison believes the tolerance band should be increased to 20% and that the imbalance charge should be cost-based. SW Gas supports the provisions in the Settlement.

SCUPP comments that the rate paid for positive imbalances should be higher and the rate paid for negative imbalances should be lower.

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

Sunpacific comments that the proposed approach does not recognize the differential value of gas delivered to different locations at different times. Sunpacific is also critical of the proposal because it proves for no limits on imbalances during the month of consumption, instead giving the customer 30 days to get within the 10% limit. It suggests workshops to ameliorate this problem over the longer term. Sunpacific opposes the Settlement's provisions as representing a subsidy to "sloppy" noncore customers from core customers.

Salmon believes standby service should be offered by third parties in order to get the utilities out of the noncore procurement business. Hadson suggests stricter balancing rules and proposes very specific rules for implementation of standby service. Enron suggests the Commission require the utilities to establish electronic bulletin boards to facilitate trading.

Phillips proposes a quarterly make-up period and a lower standby service rate.

Indicated Producers is puzzled by the Settlement's unexplained differences between the policies of the three utilities. It believes SoCal should provide some opportunity for a customer to cure a negative imbalance, especially in light of the restrictive tolerance of 7%. Indicated Producers also comments that the Settlement rules for balancing and standby services may also allow SoCal too much discretion in determining when to apply charges or purchase gas. This discretion, according to Indicated Producers, could result in discrimination between customers and should be eliminated.

i. Industrial Customers

CIG objects to the Commission's goal of discouraging balancing and standby services and supports the provisions of the Settlement.

CACP argues that the monthly usage tolerance should be extended to 20% and that penalties should reflect the actual cost of providing the service.

Barry supports more liberal balancing procedures and proposes that the volumes be based on monthly averages rather than daily maximum takes which would, according to Barry, reduce the utilities' administrative costs and take some pressure off of large customers.

j. DGS

DGS supports generally the standby and balancing provisions except that it believes the 150% standby rate is excessive. It comments that the trading mechanism should be administered by the utilities via computer bulletin board.

2. Discussion

We agree with PG&E and DRA that the balancing provisions of the Settlement and the proposed rules are unlikely to encourage customers to plan their gas takes carefully, and that utilities and their ratepayers should not be responsible for the costs associated with imbalances. As PG&E points out, customers could deliver no gas in one month and make-up the entire imbalance the following month. Customers could also true-up imbalances by creating additional, planned imbalances in the opposite direction during subsequent months. We agree with DRA that the Settlement provisions balancing services amount to free storage. For SoCal this is especially critical because of its storage constraints. A 30% tolerance with a 30-day make-up period for SoCal is not reasonable under the circumstances.

Our adopted rules for balancing and storage will recognize that balancing services should not replace storage. They will recognize the costs of using utility resources and also promote well-planned nominations by customers.

As we said in D.90-07-065, we believe trading between customers to equalize imbalances is reasonable if it would not complicate utility operations. Those who benefit from trading, and not the general body of ratepayers, should bear the cost of administering a trading program. We will not permit the utilities to pass along to ratepayers the costs of administering a trading program. We encourage non-utility interests to administer such trading programs rather than relying on utilities.

Our adopted rules for balancing and standby services are as follows:

> The utilities shall provide balancing services to noncore customers. The tolerance for balancing services shall be 10% of customer nominations.
>
> Where positive imbalances fall outside the 10% tolerance at the end of a 30-day period, utilities shall purchase noncore customers' overnominations at a rate equal to the lower of the lowest incremental cost of gas or the system for that month or 50% of the core WACOG for the month.
>
> Where negative imbalances fall outside the 10% tolerance at the end of a 30-day period, utilities shall charge customers for standby services. Standby service gas rates shall be equal to the higher of 150% of the core WACOG for the month or the highest incremental cost of gas for the month. Standby service shall

> have the lowest priority during periods of curtailment.
>
> Noncore customers may trade imbalances to avoid liability for them. The utilities may administer trading programs. If they do so, no related costs shall be recovered solely, if at all, from participants in the trading program.

G. <u>Excess Gas Supplies</u>

Notwithstanding our view that utilities should generally limit their gas procurement activities to the core, D.90-07-065 permitted utilities to sell excess core gas under certain circumstances. The proposed rules recognized that core ratepayers would be better off if the utilities were permitted to sell excess gas in cases where they would otherwise incur contract penalties or take-or-pay charges which would arise when core demand is substantially lower than expected. Under the proposed rules, 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 could be made only to avoid extraordinary charges. The utilities could not sell the gas through affiliates because we wish to avoid the auditing problems that arise with affiliated transactions. The utilities could not sell excess gas simply to avoid storing it and could not use 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.

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. The exception to the Settlement provisions on excess gas sales is that PG&E would be permitted to sell gas to SoCal or SDG&E.

b. PG&E

PG&E supports the rules proposed for excess gas sales so long as a specific provision is added that it applies only to sales to noncore customers and not to sales made to other utilities. PG&E comments that it uses off-system sales to SoCal to balances its system on a day-to-day operational basis.

c. SoCal

SoCal asks that the proposed rule be modified to permit sales of excess gas to persons other than its noncore customers, the approach taken by the Settlement.

d. UEG and Wholesale Customers

Edison supports the proposed rules regarding sales of excess gas.

SCUPP recommends prohibiting the sale of excess core gas supplies to noncore customers.

e. DRA

DRA comments that D.90-07-065 retreats from the original proposal in R.90-02-008 to place shareholders at risk for the costs of surplus supply. It recommends this provision be reinstated in order to send a strong signal that procurement policies should be designed to avoid contract penalties.

f. TURN

TURN recommends that all core gas sales should be explained in the annual reasonableness report.

g. CEC

CEC supports the proposed rules, but suggests clarification of whether "extraordinary charges" are the same as "contractual penalties" and whether "contractual penalties" are intended to refer to any charges other than take-or-pay charges.

h. Independent Producers and Marketers

Sunpacific suggests that excess core gas sales should be made at the point of purchase for transport by the purchaser rather than the selling utility. This would preclude utilities from using their transport rights to move supplies to alternate buyers.

Phillips prefers the OIR's original proposal to prohibit excess gas sales to the rule proposed in D.90-07-065 which would permit such sales under some circumstances. It opposes the Settlement provisions for sales of excess gas.

Indicated Producers seeks clarification on whether the proposed rules contemplate the utility's use of its interstate capacity rights to transport the excess core gas sales on behalf of its noncore customers. It argues that the utilities should not be permitted to use their interested capacity rights directly to transport excess core gas sold to noncore customers. The Settlement parties, according to SoCal, have not justified the Settlement provision which would allow PG&E to use its interstate transportation rights to sell excess gas to SoCal. Indicated Producers also asks the Commission to describe more specifically the types of contract penalties that may justify sales of excess core gas to noncore customers, and suggests that the Commission apply only take-or-pay charges which are the subject of contracts signed before the issuance of the OIR on February 7, 1990.

i. Industrial Customers

CIG suggests making the proposed rule more explicit and recognizing that PG&E must occasionally sell excess gas to other gas utilities because of operational constraints.

j. State of New Mexico

The State of New Mexico supports the proposed rules for sales of excess gas.

2. Discussion

The proposed rules and the Settlement provisions are substantially the same. We will adopt them without changes except that we will require the utilities to chronicle in reasonableness reviews all sales of excess core gas to noncore customers.

Our adopted 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.
>
> PG&E may sell excess core gas to SoCal and SDG&E to meet their core customer requirements.
>
> In each reasonableness review, or related proceeding, the utility shall provide accounting and operational information regarding each sale of excess core gas to noncore customers.

V. Implementation

1. Settlement

The Settlement would suspend any review of incentives, such as those which were the subject of D.90-07-065, until after August 1, 1994. The settling parties seek approval of the Settlement no later than October 1, 1990. Implementation would be complete no later than August 1, 1991 under the following schedule:

By November 30	Utilities distribute proposed tariffs to all parties
December - January	Workshops hold to address proposed tariffs and other implementation issues
By February 1	Advice lettor filings
February - March	Finalize dotails of program
By August 1, 1991	Full implemontation

The Settlement requests that the Commission consider the demands of this schedule on the parties when it considers the procedural options for considering capacity brokering in R.88-08-018 and rate design in I.86-06-005. The Settlement parties also recommend suspending any changes to the pilot storage banking program for another year.

2. Independent Producers and Marketers

Salmon proposes that several of the issues under consideration, because of their importance, require hearings:

> Rate design for transmission and core subscription and the forecast for estimating demand for those services;
>
> The effect of FERC decisions regarding allocation of firm interstate capacity on the usefulness of intrastate firm transmission rates;
>
> The method to be used in determining the distribution of required takes from A&S suppliers by noncore customers;
>
> The feasibility of third parties supplying standby service gas and the utilities' cost of standby service, if they are to provide it.

3. Discussion

We have already discussed our view that we cannot agree to forego review of incentives for any time period. As for the storage banking program, we will not here make commitments which are appropriately and presently being addressed in the storage proceeding, I.87-03-036, and after providing an opportunity for parties to that proceeding to comment.

The regulatory changes we adopt today will require some time to implement. The Settlement parties urge us to suspend activity in related proceedings in order that the parties may devote their attention to the rules adopted today. We recognize that resource constraints limit our ability and that of the parties to simultaneously move forward with implementing today's program, developing a capacity brokering system, and reconsidering rate design and cost allocation issues in I.86-06-005.

Some of the Settlement provisions we adopt today are interim in nature. Specifically, the transportation services we approve are not substitutes for a capacity brokering program for reasons we have discussed earlier. We delayed review of capacity brokering in order to accommodate our schedule in this proceeding. Because of our view that the transportation services adopted today are not permanent, we hesitate to delay review of capacity brokering any longer. We prefer to defer our review of long-run marginal cost rate design and cost allocation issues. Accordingly, hearings scheduled to begin January 7, 1991 in I.86-06-005 will consider only the rate design issues related to all volumetric rates for noncore transportation services, discussed in Section IV.C. We intend to issue a decision on that matter in time for final implementation of the rules we adopt today. We will also move forward with capacity brokering as soon as possible after final tariffs are filed which would implement today's rules.

We will adopt the schedule set forth by the parties but make some minor modifications to assure that the process permits implementation by August 1, 1991. Our intended schedule for implementing the rules adopted today is as follows:

By November 10	Utilities distribute proposed tariffs to all parties
November - December	Workshops held to address proposed tariffs and other implementation issues
By January 10	Advice letter filings
January - February	Finalize details of program
By August 1, 1991	Full implementation

We also need to address the schedule for ACAPs and BCAPs. PG&E has recently filed an ACAP application which will proceed under the previous schedule. Beginning with SoCal's 1991 filing, we will proceed on the two-year schedule and all subsequent cost allocation proceedings will be for a two-year period.

Findings of Fact

1. D.90-07-065 proposes rules for restructuring regulation of natural gas utilities procurement and sales activities and relationships with affiliates.

2. D.90-07-065 required respondent utilities to file comments on the proposed general guidelines and sought comments from other parties.

3. Several parties filed on August 15, 1990, a request to adopt a settlement. The signatories to the settlement are PG&E, SoCal, SDG&E, CIG, Mock, TURN, GasMark, and Enron.

4. On August 15, 1990, interested parties filed comments on the rules proposed in D.90-07-065.

Conclusions of Law

1. The rules attached to this decision as Appendix A are reasonable and should be adopted.

2. The utilities should be ordered to submit to all parties to this proceeding, by November 10, 1990, proposed tariffs which would implement the rules attached to this decision as Appendix A.

3. The utilities should be ordered to file, by January 10, 1990, advice letters and tariffs implementing the rules adopted in this decision.

4. The Commission should consider, in I.86-06-005, alternatives to demand charges which are consistent with the policy of setting rates according to the costs imposed on the system by customer classes and which would promote efficient use of the gas supply system.

INTERIM ORDER

IT IS ORDERED that:

1. The rules attached to this decision as Appendix A are adopted.

2. Southern California Gas Company (SoCal), San Diego Gas and Electric Company (SD&G&E), and Pacific Gas and Electric Company (PG&E) shall submit to all parties to this proceeding, by November 10, 1990, proposed tariffs to implement the rules attached to this decision as Appendix A.

3. SoCal, PG&E, and SDG&E shall file, by January 10, advice letters proposing tariffs to implement the rules adopted in this proceeding and attached as Appendix A. The advice letters shall be served on all parties to this proceeding.

4. This proceeding shall remain open for the purpose of considering utility incentives.

5. PG&E, SDG&E, and SoCal shall propose in I.86-06-005 alternatives to demand charges which are consistent with the policy of setting rates according to the costs imposed on the system by customer classes and which would promote efficient use of the gas supply system. Those proposals shall be submitted according to the schedule set forth by the administrative law judge in that proceeding.

6. SDG&E shall survey its noncore, non-UEG customers for their views on SDG&E conduct with respect to the treatment of noncore and UEG gas transportation and report to the Commission six months from the date of full implementation of the rules adopted today.

This order is effective today.

Dated September 25, 1990, at San Francisco, California.

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

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

I will file a written concurring opinion.

/s/ G. MITCHELL WILK
President

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

NEAL J. SHULMAN, Executive Director

PROPOSED RULES FOR GAS UTILITY PROCUREMENT

Utility Gas Marketing Affiliates and Gas Sales to Noncore Customers

Utility gas marketing affiliates shall maintain separate facilities, books and record of account, which shall be available fore inspection by the Commission staff upon reasonable notice.

Employees of the gas utilities shall not perform any functions for utility affiliates except those services which they offer to others on an equal basis, and utilities shall not share employees with marketing affiliates.

Gas utilities shall not reveal to their affiliate any confidential information provided by customers or non-affiliated shippers to secure service. Confidential utility information shall be made made available to all shippers if it is made available to utility marketing affiliates.

Utilities shall identify and remove from their cost of service all costs, including administrative, general, operating and maintenance costs, incurred by a marketing affiliate, and thereafter prohibit the booking to the partner utilities' system of account costs incurred or revenues earned by the marketing affiliate.

Utilities shall not condition any agreement to provide transportation service, to discount rates for such service, or to provide access to storage service or interstate pipeline capacity to an agreement by the customer to obtain services from any affiliate of the gas utility, except for the provisions contained herein respecting the direct purchase of gas by noncore customers from PG&E's affiliate, A&S, for the period specified herein.

Utilities shall disclose in reasonableness reviews or other such regulatory proceedings each transaction between the parent utility and its marketing affiliate, with sufficient information on the terms and conditions of each transaction as to permit an evaluation of the nature of such transactions. The same information shall be provided to Commission staff at any time upon reasonable notice.

Each gas utility shall submit, within 90 days of the effective date of this decision, a written report, available for public inspection, stating how the utility plans to implement these standards of conduct with respect to any existing affiliate activities in the California market.

Gas utilities shall not procure gas for or sell gas to noncore customers except as otherwise permitted by these rules.

APPENDIX A
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Core Subscription Service

Each gas utility shall offer a core subscription sorvico. That service shall provide to qualified noncore customors both gas and transportation for gas. Noncore customers customors may take all or a portion of their requirements as core subscription customers.

Core subscription customers' gas shall receive tho samo priority as the highest level priority for noncore customers. Curtailments of transportation among core subscribers shall be according to existing end use priorities. Core subscription customers' cost of transportation will be equal to the rate for the utility's highest priority noncore transportation rate.

Core subscription customers' cost of gas will equal that offered to core customers except that the price shall be set each month at the actual recorded WACOG lagged one month, as set forth in D.89-04-080. In addition, core subscription customers shall pay a brokerage fee in the amount adopted in utilities' cost allocation proceedings or other appropriate proceedings.

In order to qualify for core subscription, customers must make a two-year commitment for 75% of their annual nomination. Nominations may be for full requirements or partial requirements. Partial nominations shall be a stated annual volume which may be adjusted seasonally in accordance with the customer's historic usage patterns as provided in D.88-03-085, Ordering Paragraph 2. Utility sales gas will be deemed to be the first gas through the meter.

Take-or-pay penalties for procurement services shall be forgiven to the extent the customer's reduced gas consumption is due to force majeure, curtailments, or service interruptions imposed by the utility.

Take-or-pay penalties for procurement services shall be equal to the utility's average cost of gas inventory charges or similar unavoidable costs, if any. Until issuance of a decision setting forth a cost-based charge, the take-or-pay procurement service charge will be stated 14% of the current WACOG of the utility gas supply portfolio.

Use-or-pay penalties for core subscription transportation services shall be equal to those imposed for the highest level noncore transportation service option.

To the extent that the UEG department of a combined utility purchases gas from sources other than the utility portfolio, it must do so by contracts separate and distinct from the contract underlying the utility's system supply. The utility's UEG will pay the cost of gas under such contracts. Any instances in which the gas and electric departments of a combined utility purchase gas under separate contracts from the same or affiliated suppliers shall be fully detailed in the utility's annual reasonableness review report.

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 except that customers who were previously core-elect customers will be designated core subscription customers. Customers who do not respond to the utilities notice before the end of the 120 notice period will retain their pre-existing services during the 120-day period.

Utilities will file cost allocation applications on a two-year cycle.

A utility may file an advice letter requesting a core rate adjustment 45 days before the end of the first year of its cost allocation test year if the percentage adjustment to bundled core rates required to amortize the first year's net over or undercollection in the core PGA and core Fixed Cost Accounts (nine months recorded and three months forecasted) over one year of previously adopted core sales would exceed 5%. Such an advice filing must include complete workpapers and shall not propose any change in adopted cost allocation or rate design other than the rate changes necessary to amortize the net core over or undercollection.

<u>Transportation Services</u>

After taking into account system supply gas from California production, Pacific Offshore Pipeline Company and Pacific Interstate Offshore Company, SoCal shall reserve for system supply purposes sufficient interstate pipeline capacity on the El Paso and Transwestern systems (1) to serve "cold year" requirements of core (P-1 and P-2A) customers, and (2) to provide a reasonable allowance for company use and lost and unaccounted for (LUAF) gas. The calculation of the amount of capacity to be reserved for the core market shall also take into account the capacity needed to have sufficient gas in storage to serve core peak day and cold year winter season requirements. The total capacity allocated to the service of P-1 and P-2A customers on El Paso and Transwestern need not be the same each month. SoCal may adjust the amount of capacity reserved for the core market consistent with these rules no more than once a year.

Interstate pipeline capacity will be reserved by SoCal for the core market on a pro rata basis between El Paso Natural Gas Company and Transwestern Pipeline Company. The pro rata amount will be computed as a ratio of SoCal's capacity rights on an individual pipeline to SoCal's total capacity rights on both pipelines. Capacity reserved for the core market on El Paso and Transwestern will be reserved on a pro rata basis divided at each of the "constraint" points on each of the two pipeline companies to the extent permitted and feasible under their tariffs and FERC regulations. These rules do not modify the terms of the long-term contract between SoCal and SDG&E which was approved by the Commission in Resolution G-2921.

The SoCal contract with SDG&E shall be subject to the outcome of further proceedings in the capacity brokering case with respect to the integration of long-term contracts into the firm transportation program set forth in these rules.

Pacific Gas and Electric Company (PG&E) shall make available to noncore transportation customers 450 MMcf per day of its pipeline capacity. Of this 450 MMcf per day, 250 MMcf per day shall be over PG&E's Pacific Gas Transmission (PGT) line to Canada and 200 MMcf per day over El Paso.

Pursuant to Resolution G-2921, the Commission has approved the assignment of firm interstate pipeline capacity and storage rights by SoCal to SDG&E. Implementation of these provisions remains subject to the tariffs and regulations applicable to the interstate pipeline systems. Upon implementation of the provisions of the SoCal/SDG&E contract and Resolution G-2921, SDG&E's noncore customers will have pro rata access to such rights.

SDG&E may procure gas for its noncore, non-UEG customers with transportation service at all levels. SDG&E's noncore, non-UEG customers receiving transportation service at levels 2 through 5 must, in order to purchase gas from SDG&E, commit to the same obligations as core subscription customers.

The utilities shall make available five levels of transportation service:

<u>Service Level 1</u> -- core service. All capacity reserved for any customer is recallable to preserve Service Level 1 transportation access for core customers.

<u>Service Level 2</u> -- firm service for noncore customers under an annual contract with a 75% use-or-pay obligation and a use-or-pay penalty equal to 80% of the firm transportation rate applicable to the customers. This service shall require a two-year commitment. Core subscription service includes Service Level 2 transportation. The transport rate is not negotiable.

<u>Service Level 3</u> -- interruptible service under an annual contract with a 75% use-or-pay obligation and a use-or-pay obligation penalty equal to 60% of the customer's applicable transportation rate. The utility and the customer may negotiate rates for Service Level 3.

<u>Service Level 4</u> -- interruptible service under a monthly contract subject to a 75% use-or-pay obligation and a use-or-pay penalty equal to 30% of the customer's applicable transportation rate. The utility and the customer may negotiate rates for Service Level 4.

<u>Service Level 5</u> -- interruptible service for nomination periods of less than a full month with no use-or-pay obligation. The utility and the customer may negotiate rates for Service Level 5.

Noncore customers shall be permitted to split their requirements among noncore Service Levels. Where the service level requires an annual contract commitment, the customers will nominate quantities consistent with their historic requirements or, otherwise, will be required to demonstrate the basis for such quantities. In lieu of a stated annual contact quantity, a noncore customer also may select "full requirements" service under Service Level 2. A "full requirements" customer is prohibited from using alternate fuels (except in the event of curtailment, to test alternate fuel systems or where the utility has expressly authorized use of alternate fuels). To the extent that a full requirements customer uses alternate fuels for other reasons, the customer shall be subject to a use-or-pay penalty equal to 80% of its applicable firm transportation rate.

The coordination of full requirements customers needs with the nomination of stated contract quantities for firm transportation shall be addressed in the tariff implementation workshops in R.90-02-008.

For monthly service (Service Level 4), the customers's Maximum Daily Quantity (MDQ) will be equal to his contract quantity for the month expressed in MDth per day. For service under annual contracts (Service Levels 2 and 3) the utility shall negotiate an MDQ that is consistent with the expected monthly demand profile of the customer. The customer's average MDQ over the year will have to exceed the annual contract quantity in order to account for daily and monthly fluctuations in gas usage. Implementation of the MDQ procedure shall be addressed in the tariff implementation workshops in R.90-02-008.

Initial allocation of Service Level 2 capacity shall be based on customers' pro rata share of nominations where customers' nominations in total exceed available capacity. The utilities may confirm the reasonableness of customers' nominations by reviewing historical demand and other circumstances, including operational changes designed to accommodate air quality regulations or objectives.

Use-or-pay penalties for transportation services shall be forgiven to the extent the customer's usage falls below the use-or-pay level due to service interruptions imposed by the utility or upstream pipeline or force majeure conditions, excluding required maintenance of customer's facilities, plant closures, economic conditions or variations in agricultural crop production.

Each utility shall file with the Commission Advisory and Compliance Division estimated capacity allocation between transportation service levels on each interstate pipeline. The filing shall be made no later than the deadline for noncore customers to make their annual and biannual service choices.

Transportation Curtailments

Curtailments for Levels 2 and 3 shall be according to existing end use priorities. For Levels 4 and 5, the utility shall curtail customers according to the level of payment they make for service, with highest paying customers to be curtailed last. For customers who pay the same rates, the utilities shall curtail customers on a pro rata basis.

For Service Levels 2 and 3, UEG customers shall be curtailed ahead of cogeneration customers where the UEG customer pays an equal or lower rate. In Service Levels 4 and 5, where the UEG customer pays more than the cogeneration customer, the cogeneration customer shall be curtailed ahead of the UEG customer.

Long-Term Contracts

Customers with long-term contracts in existence on the effective date of these rules, and whose contracts do not specify otherwise, shall receive at the contract rate Service Level 3 service. Those customers may alternatively opt for Service Level 2 service at a rate to equal to one-half the existing default rate and one-half the existing contract rate, plus a 12 cent per decatherm surcharge. Express contract terms and conditions of existing contracts shall not be changed as a result of the rules herein.

Nothing in these rules shall be construed to amend the Commission's existing policy regarding long-term contracts for pipeline capacity, set forth in D.89-12-045, until and unless the Commission sets forth new policy as part of capacity brokering programs.

Noncore Gas Purchases

Until an integrated interstate-intrastate capacity brokering program is adopted, the utilities will use their capacity rights to purchase gas supplies identified by individual customers on a non-discriminatory "best efforts" basis, and resell the gas to the customer. Alternatives to this arrangement, if required, shall be submitted to the Commission in a petition for modification. Service Level 2 is "firm" at the burner tip until an integrated interstate-intrastate capacity brokering program is adopted.

Noncore transportation customers may transport Canadian gas over PGT subject to the following conditions. Until August 1, 1994, noncore customers may negotiate gas supply arrangements only with producers under contract with Alberta and Southern (A&S). Once a noncore customer has made such an agreement with an A&S supplier, PG&E will arrange to have the gas purchased by A&S under existing gas purchase agreements and will arrange to have the gas transported by PGT. Noncore customers may purchase gas from any Canadian supplier after August 1, 1994.

Services to Electric Utilities and Other P-5 Customers

UEGs and other end use priority P-5 customers generally shall be subject to the same terms and conditions applicable to other noncore customers except that P-5 customers shall not be permitted to nominate more than 65% of their requirements into Service Levels 2 and 3 in the aggregate. P-5 customers shall not be eligible to receive their full service requirements from utility core subscription services. These conditions may be changed according to rules adopted for capacity brokering programs.

SDG&E may procure gas for its UEG department.

Balancing and Standby Services to Noncore Customers

The utilities shall provide balancing services to noncore customers. The tolerance for balancing services shall be 10% of customer nominations.

Where positive imbalances fall outside the 10% tolerance at the end of a 30-day period, utilities shall purchase noncore customers' overnominations at a rate equal to the lowest incremental cost of gas on the system for that month or 50% of the core WACOG for the month.

Where negative imbalances fall outside the 10% tolerance at the end of a 30-day period, utilities shall charge customers for standby services. Standby service gas rates shall be equal to the higher of 150% of the core WACOG for the month or the highest incremental cost of gas for the month. Standby service shall have the lowest priority during periods of curtailment.

Noncore customers may trade imbalances to avoid liability for them. The utilities may administer trading programs. If they do so, related costs shall be recovered, if at all, solely from participants in the trading program.

Sales of Excess Core Gas Supplies

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.

PG&E may sell excess core gas to SoCal and SDG&E to meet their core customer requirements.

In each reasonableness review, or related proceeding, the utility shall provide accounting and operational information regarding each sale of excess core gas to noncore customers.

(END OF APPENDIX A)

Pacific Gas and Electric Company

245 Market Street
San Francisco CA 94106
415 973-2058

Daniel E. Gibson
Vice President
Gas Supply

PG&E

September 20, 1990

President G. Mitchell Wilk
California Public Utilities Commission
505 Van Ness Avenue, Room 4025
San Francisco, CA 94102

Dear President Wilk:

Since filing the OIR settlement on August 15, extensive discussions have continued between key settlement parties and the Alberta Petroleum Marketing Commission in consultation with the A&S producers. These discussions occurred in order to work out the details for implementing the direct supply arrangements as discussed at pages 14 - 16 of the Settlement and Agreement.

I am happy to report to you that our efforts have been successful. Attached are mutually agreeable procedures for implementing direct supply arrangements between PG&E's firm transportation customers and A&S producers. I have been authorized by the other participating settlement parties (California League of Food Processors, California Industrial Group, California Manufacturers Association, Mock Resources, Inc., Southern California Gas Company, and TURN) to transmit this agreement to you. Separate letters from the Alberta Energy Minister and the Alberta Petroleum Marketing Commission should arrive shortly conveying Alberta support for this agreement.

Please feel free to contact me if you have any questions about the agreement or need further information.

Sincerely,

DANIEL E. GIBSON

DEG:cga

Attachment

cc: Commissioner Frederick R. Duda
Commissioner Patricia M. Eckert
Commissioner Stanley W. Hulett
Commissioner John B. Ohanian
Settlement Parties

IMPLEMENTATION PROCEDURES FOR DIRECT SUPPLY ARRANGEMENTS BETWEEN PG&E's FIRM TRANSPORTATION CUSTOMERS AND A&S PRODUCERS

The provisions of the Settlement and Agreement (pp. 14-16) establish the general framework by which PG&E's firm transportation customers (Service Level 2) may make direct supply arrangements with natural gas producers currently under contract to A&S. The Settlement and Agreement also provides that further details for implementing these direct supply arrangements will be developed during the workshop period (p. 15, note 9).

Several of the Settlement Parties and representatives of the Alberta Petroleum Marketing Commission, in consultation with A&S producers, have met and developed mutually agreeable procedures to implement direct supply arrangements between PG&E's firm transportation customers and A&S producers. The procedures are set forth below.

1. Noncore, non-UEG customers of PG&E will be free to enter into supply arrangements directly with A&S producers and then commit for firm transportation service (Service Level 2).

2. A&S producers will negotiate supply arrangements directly with end-users. Each A&S producer will have available for these direct supply arrangements a

pro-rata proportion of the 250 MMcf/d, based on existing A&S supply contracts. Only reserves contracted to A&S will be available for this purpose.

3. Producers and consumers will be allowed to use marketers or agents to aggregate supplies and markets and to enter into arrangements on their behalf.

4. Once each PG&E noncore customer has negotiated its individual supply arrangements in each year with an A&S producer or producers, and determined how much of its requirements will be supplied <u>via</u> this mechanism, the customer will make its commitments to PG&E for firm transportation service (Service Level 2).

5. In each open season, noncore customers will be free to acquire supplies across PG&E's northern and southern systems in whatever proportion they choose, subject to the aggregate amount of firm service available across each system as provided for in the Settlement and Agreement.

6. For each open season of the three-year term of the Settlement and Agreement, two rounds of negotiation are contemplated to allow end-users to arrange their supply contracts with A&S producers. The following procedures will apply:

Year One

a. Initial volume assigned to each producer.

b. First round of negotiations takes place.

c. Contracts tabulated and customers signing contracts during this round commit for firm transportation service.

d. Any difference between 250 MMcf/d and contractual total is redistributed among A&S producers on the same basis as the initial allocation.

e. Round two takes place.

f. Contracts tabulated and customers signing contracts during this round commit for firm transportation service.

g. Any difference between 250 MMcf/d and contractual total (both rounds) can first be used by PG&E for system supply and, second, be made available to customers in lower priority service levels.

h. If less than 150 MMcf/d of contracts are signed after the two rounds, then producers' rights of participation in sales of the remaining volumes, as provided for in "g" above, are determined by their share of sales in rounds one and two.

Year Two

Same as year one.

Year Three

All provisions remain the same as years one and two, except that if less than 200 MMcf/d has been contracted for in round one, then only those producers committing volumes in round one will be eligible to participate in sales in round two or in any subsequent sale of the remainder. The rights of participation in round two and in any sales of amounts remaining after round two will be determined by each producer's share of sales in round one.

7. A&S will receive credit against existing contract volume requirements for the full amount of the producer's initial pro-rata share if the 250 MMcf/d is fully utilized. If the 250 MMcf/d is not fully utilized for supply arrangements under this agreement, A&S will receive credit for the greater of (1) the volume actually sold by the producer via this mechanism, up to the producer's initial pro-rata share or, (2) a portion of the producer's initial pro-rata share which is equivalent to the percentage utilization of the 250 MMcf/d.

8. The open seasons for firm transportation and direct supply arrangements will occur annually; there will be no automatic extension of these arrangements. If the CPUC approves firm transportation service for longer than one year, the producers and customers

will have the ability to match the terms of the supply contracts with that of the transportation service, subject to the provisions of Nos. 4 and 5 above. No supply or transportation service under these arrangements will extend boyond the term of the Settlement and Agreement (August 1, 1994).

9. To the extent the 250 MMcf/d is not fully contracted for, or taken by, noncore customers desiring firm transportation service, remaining volumes can be used first by PG&E for system supply.

10. Tier III or alternative supply arrangements as approved by the A&S producers can be used by noncore, non-UEG and UEG customers using lower priority service levels.

11. Limitations or increases in capacity on PGT will not affect the 250 MMcf/d firm service unless customers within that service level in PG&E's service area are curtailed.

12. The supply arrangements in this agreement will remain in place until at least August 1, 1994 (or, if implementation occurs after August 1, three years from the date of implementation). The commitment to purchase only from A&S producers under terms of this

agreement will remain in effect regardless of whether capacity brokering is introduced on the PGT or PG&E systems in the interim.

(END OF APPENDIX B)

September 20, 1990

D.90-09-089
R.90-02-008

G. MITCHELL WILK, Commissioner, concurring:

This decision further modifies the regulatory structure of the gas industry and continues to recognize and support the competitive nature of gas procurement, allowing the market to work effectively to the advantage of California's core and noncore ratepayers. With the establishment of firm transportation service, the utility advantage in providing procurement services, whether perceived or real, has been greatly reduced. These rules establish a program of transition toward the increasingly competitive future of the gas market that will come with capacity brokering and the availability of new pipeline capacity. As such, I regard them as interim in nature.

In reaching this decision, I realize that while I believe it greatly improves the operating environment and competitiveness of the gas procurement market generally and the transportation options available to the noncore, parties will argue it falls short of reaching <u>all</u> their needs. It does establish firm transportation for noncore customers without compromising the core ratepayers needs. It does reduce the ills of our core-elect structure. It does <u>not</u> insulate parties from the movement toward a more competitive California gas market. While it is an improvement, it is not the ideal solution; that would be new pipeline capacity and a capacity brokering program.

I recognize the magnitude of the task undertaken by those parties to this proceeding who endeavored to reach a settlement of the issues. In February, with the opening of this rulemaking, I said I would "look to the parties to help this Commission formulate policies that will both promote and realize the benefits of a competitive noncore market." Through comments, and for some, through negotiation, the parties have done just that.

I am pleased that these new rules, in large part recommended by the settlement parties, meet the basic goals we pursued in opening the rulemaking: rationalizing transmission access and avoiding the distortions of utility procurement without imposing undue risk on the core ratepayer.

G. MITCHELL WILK, Commissioner

September 25, 1990
San Francisco, California