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Decision 94-03-050 March 16, 1994

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY for Authority to Adjust its Electric Rates Effective November 1, 1991, and to Adjust its Gas Rates Effective January 1, 1992, and for Commission Order Finding that Gas and Electric Operations During the Reasonableness Review Period from January 1, 1990 to December 31, 1990 were Prudent.	Application 91-04-003 (Filed April 1, 1991)

(See Appendix A for appearances.)

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OPINION

I. Introduction

By this decision, we render findings on the reasonableness of Pacific Gas and Electric Company's (PG&E) Canadian gas purchases covering the period February 1, 1988 through December 31, 1990.

Based upon our review of Canadian gas purchases, we find that PG&E was imprudent in its failure to take steps to negotiate prices based on competition among Alberta gas producers for sales into PG&E's consuming market during the 1988-90 record periods. We decline to allow recovery from ratepayers of $90,133,000 of gas costs, plus accrued interest (as derived in Appendix B) which PG&E could have saved had it pursued prudent alternative actions in procuring Canadian gas supplies. We further find that the disallowances proposed by various intervenors overstate the magnitude of savings which PG&E realistically could have achieved during the record periods. We acknowledge that various regulatory and market impediments limited PG&E's ability to extract price concessions from Canadian producers. Nonetheless, we find that PG&E was not completely without means to bargain for Canadian gas prices lower than it paid during the record periods. The primary means by which PG&E could have achieved such savings was through more aggressive use of core election and transport access in negotiations with its existing Canadian suppliers. As another option, PG&E could have procured at least a portion of its Canadian supplies from alternative Canadian suppliers at lower prices.

II. Procedural Background

In April 1989, PG&E filed Application (A.) 89-04-001 under its Energy Cost Adjustment Clause (ECAC). The filing included a request for a finding of reasonableness of 1988 record period gas operations. The Division of Ratepayer Advocates (DRA) subsequently mailed a Reasonableness Report covering the 1988 record period which concluded PG&E's operations were reasonable. On January 29, 1990, the assigned administrative law judge (ALJ) ruled to defer all reasonableness issues concerning PG&E's 1988 record period gas operations due to a pending investigation into PG&E employee gas procurement actions (i.e., the Satrap Investigation). On July 31, 1990, DRA filed a motion to defer consideration of PG&E's 1989 record period, stating that its investigation of 1988-89 record period gas reasonableness issues for A.89-04-001 was still ongoing and, without its results, DRA was unable to make final recommendations. On September 11, 1990, an ALJ ruling granted DRA's motion. PG&E subsequently filed its application in the present docket on April 1, 1991 under its ECAC procedure, requesting a finding on the reasonableness of its 1990 record period gas and electric operations.

By letter dated September 28, 1990, DRA informed the ALJ that during its reasonableness investigation in the Satrap matter, DRA gained access to gas supply contracts between PG&E's Canadian affiliate and Alberta producers. DRA's review of these contracts raised new issues concerning the reasonableness of Canadian gas purchases not addressed in DRA's previous report on the 1988 record period. DRA's Canadian gas investigation led to the issuance of a September 16, 1991 report addressing the reasonableness of PG&E's Canadian gas purchases for the 1988-90 record periods. The ALJ ruled that the Satrap investigation need not further delay Commission action on the remaining gas reasonableness issues for the deferred record periods. The scheduling of reasonableness issues was designated as Phase II.[1] A prehearing conference held November 1, 1991 addressed the scoping and scheduling of Phase II.

Because of the complexity and significance of prudence issues raised in DRA's September 16, 1991 report, a proceeding phase was designated to address that as a separate topic. Accordingly, the assigned ALJ consolidated into this docket the reasonableness of Canadian gas purchases for the 1988-1990 record periods, as Phase II-A. A separate Commission order shall address Phase II-B covering the remaining electric and gas department reasonableness issues for the 1988-90 record periods.[2]

Under Phase II-A, PG&E offered into evidence its case-in-chief testimony on gas reasonableness for record periods covering 1988 and 1989 (originally served in A.89-04-001 and A.90-04-001, respectively) and for 1990 (served on April 1, 1991 under this docket.) PG&E served rebuttal testimony to DRA on February 19, 1992, and rebuttal to intervenors on April 8, 1992.

In addition to PG&E and DRA, the following intervenors also sponsored direct and rebuttal testimony in Phase II-A: Sacramento Municipal Utility District (SMUD), Toward Utility Rate Normalization (TURN), Independent Petroleum Association of Canada (IPAC), and the Canadian Petroleum Association (CPA). The Alberta

1 Phase I of this docket dealt with PG&E's forecast ECAC expenses.

2 Remaining Canadian issues in this docket which are not addressed in this decision include (1) review of PG&E's prospective restructuring of its Canadian gas supply arrangement and (2) the effects of Canadian gas costs flowed through to Electric Department costs, particularly Northwest purchased power costs. A pending DRA motion dated April 12, 1993 seeks to hold open Phase IIA of this proceeding to consider the effects of imprudent Canadian gas costs on prices paid to Qualifying Facilities (QFs) and on geothermal prices.

Petroleum Marketing Commission (APMC) also filed a brief, but sponsored no testimony.

Phase II-A evidentiary hearings commenced June 1, 1992 and consumed 54 days intermittently through October 31, 1992. Opening briefs were filed January 25, 1993 with replies filed March 1, 1993.

On December 11, 1992, DRA submitted proposed transcript corrections. On January 20, 1993, PG&E submitted proposed transcript corrections covering various witnesses, including DRA's. DRA objects by letter dated January 20, 1993 to PG&E's proposed corrections of DRA witnesses' testimony. We will adopt DRA's transcript corrections. DRA does not contest PG&E's transcript corrections for its own witnesses, but objects to PG&E's corrections for DRA witnesses. PG&E's transcript corrections are hereby adopted, except we decline to adopt PG&E's corrections of DRA witnesses.

III. Overview of Phase II-A Issues

At issue in Phase II-A of this proceeding is the reasonableness of PG&E's procurement of its Canadian gas supplies. DRA, SMUD, and TURN propose disallowances based upon allegedly excessive charges for PG&E's Canadian gas purchases during the 1988-90 record periods.

Canadian gas purchases made up about 50% of PG&E's gas purchases during the 1988-90 record periods. PG&E purchased essentially 100% of its Canadian gas through a chain of affiliate transactions. PG&E's subsidiary, Alberta and Southern Gas Company Ltd. (A&S) acquired gas from about 185 Canadian producers under individual long-term contracts. A&S aggregated the gas from these producers and then transported it to the international border, where it was sold to Pacific Gas Transmission Company (PGT), a wholly-owned PG&E pipeline transport subsidiary. PGT transported the gas to the California/Oregon border where PG&E, in turn, purchased the gas based on PGT's cost-of-service tariffs approved by the Federal Energy Regulatory Commission (FERC).

There is no dispute that Canadian gas, in general, was cheaper during the record periods than gas procured from any U.S. supply basin. All parties agree that it was prudent for PG&E to maximize Canadian gas purchases. DRA, SMUD, and TURN, however, contend that PG&E could have tapped competitive market sources within Canada to yield lower gas prices in response to restructuring of the natural gas industry before and during the record periods. A brief review of the development of gas industry restructuring offers a useful context for understanding parties' disputes.

Restructuring has transformed the gas industry from wellhead production to retail end-use consumption. As a local distribution company (LDC), PG&E's gas procurement options were fundamentally influenced by regulatory industry restructuring policies at the state, federal, and Canadian governmental levels.

Under the traditional natural gas industry structure, U.S. interstate pipelines acted as wholesale gas merchants, having long-term arrangements with wellhead producers to buy dedicated reserves which were in turn sold to LDCs under corresponding long-term contracts. Interstate pipeline prices were controlled by federal regulations. By the late 1970s, it had become obvious that federal regulation of interstate gas prices was creating unacceptable distortions in the marketplace. The situation was particularly exacerbated by an outbreak of unusually cold weather in the late 1970s triggering a series of gas shortages. These shortages were caused largely because federally regulated interstate prices were too low to provide producers an incentive to sell gas in the interstate market even though demand was high. Instead, sellers assigned most gas to intrastate markets where federal price ceilings did not apply, and prices could rise to accommodate production costs and market demand.

To remedy such market imbalances, Congress enacted the Natural Gas Policy Act (NGPA) in 1978. The NGPA gradually deregulated interstate natural gas wellhead prices to allow competitive market forces to determine prices, thereby relieving supply shortages. Interstate deregulation of gas wellhead prices, in itself, was not sufficient to create a truly competitive market for gas sales. For a purchase to occur, gas must be transported from the wellhead to the end-user through pipeline facilities. Historically, interstate pipelines had refused to transport gas for parties who were not direct purchasers of their gas. Conflicts increasingly developed during the early 1980s between pipelines who were stuck with long-term contracts with producers from the pre-NGPA era and LDCs who wanted access to cheaper deregulated gas available under the NGPA. FERC responded to this problem by issuing a series of orders aimed at promoting a more competitive gas market and increasing LDCs' access to cheaper gas.

A key theme of these FERC orders was the promotion of competitive open access to interstate pipeline transport by LDCs and other direct gas purchasers. Although historically, interstate pipelines had been gas merchants, selling only gas that they owned, the FERC's restructuring orders were aimed at "unbundling" the pipelines' separate marketing functions. Interstate sales of natural gas became "unbundled" from the provision of gas transport service. Thus, an LDC became free to shop for the cheapest gas and then independently select a pipeline company to transport the gas. FERC retained regulation over the interstate transportation function, while allowing the market to determine the commodity price of gas.

The most important of these orders included FERC Order 380, issued May 1984, which eliminated the minimum bill provisions of interstate pipeline sales tariffs applicable to LDCs; FERC

Order 436, issued November 1985, which established blanket nondiscriminatory open transport access and made it possible for LDCs to convert their firm sales entitlements to firm transportation service; and Order 500 which provided methods for allocating TOP settlement costs between pipelines and their customers.

The Canadian natural gas industry also underwent a restructuring, although along somewhat different lines than in the U.S. Parties dispute exactly how industry restructuring within the Canadian gas market influenced PG&E's ability to tap competitive forces to achieve minimum prices consistent with its other utility service goals. We discuss these disputes in detail below. Here, we simply observe the general trend toward a more competitive Canadian market which began to materialize by the mid 1980s. The Canadian gas industry and governmental authorities recognized by the mid 1980s that if Canadian producers were to maintain their share of the U.S. gas market, steps had to be taken to develop a competitive Canadian gas market.

From the mid 1970s through 1984, Canadian export prices of natural gas had been mandated by the Canadian federal government. As U.S. domestic gas prices declined in the early 1980s in response to competitive market forces, government-regulated Canadian gas became increasingly uncompetitive in U.S. markets. In reaction to such competitive pressures, the Canadian government enacted a new Gas Export Policy effective November 1, 1984. This new policy allowed for gas export prices to be negotiated by the contracting parties, subject to review by the National Energy Board. We discuss the competitive implications for this pricing policy in detail in Section V.A.

In response to the restructuring of wholesale gas markets at the federal level, we initiated complementary restructuring for LDCs under our jurisdiction in the mid-1980s. Our restructuring recognized the broadening span of PG&E's supply options and changing nature of its service obligations as a franchised monopoly.

Our restructuring program was initiated in late 1985 by Decision (D.) 85-12-102 in which we directed California LDCs to offer long-term gas transportation service for customer-owned gas. We extended that obligation to short-term transportation service in D.86-03-057. Beginning with D.86-03-057, we initiated restructuring rules for LDCs under our jurisdiction to promote the development of competitive market forces in coordination with federal regulatory actions, stating:

> "The deregulation of gas at the wellhead has changed fundamentally the nature of buying and selling natural gas. What was once a highly regulated procedure is emerging as a viably competitive market. With gas sales becoming a competitive enterprise, the portion of the gas industry which remains a natural monopoly is transportation, [which]...refers generally to the movement of gas through...pipelines. In this changed world, it now makes sense to restructure our regulation with a new emphasis on transportation as a foundation, as perhaps the essential business of the gas companies we regulate." (20 CPUC2d 628, 631.)

In June 1986, we opened two companion proceedings to implement our restructuring program: Investigation (I.) 86-06-005 Re: Rate Design for Unbundled Gas Utility Services and Rulemaking (R.) 86-06-006 Re: New Regulatory Framework for Gas Utilities. As a product of these proceedings, we identified two distinct market segments:

1. A "core" segment consisting primarily of residential and commercial customers with no alternatives to gas service from the LDC and

2. A "noncore" segment consisting of large industrial customers and, in PG&E's case, its utility electric generation (UEG) department. Noncore customers could bypass the LDC and choose from a variety of

transport and procurement options outside of the LDC.

In D.86-12-010 (R.86-06-006), we adopted rules segregating gas procurement into two separate "core" and "noncore" supply portfolios which recognized the different service obligations and market options distinguishing these two sectors. We officially implemented our gas restructuring rules effective May 1, 1988. Thus, the 1988 record period represented an important transition period in PG&E's procurement of gas. We also adopted a "core-elect" option for noncore customers who would commit to purchase from the LDC in exchange for receiving core procurement service.

Throughout the 1988-90 record periods, we continued to monitor the development of our restructuring rules while recognizing various unresolved issues required further consideration. In particular, the problem of constrained pipeline capacity was an important concern in promoting truly competitive open access.

In August 1988, we instituted R.88-08-018 to address capacity brokering, procurement and reliability issues. At a hearing in November 1989, various parties complained that the utilities' procurement function for the noncore market had to be reduced or eliminated to enable noncore customers, producers, and marketers to gain access to firm transportation capacity. Complaints were raised about PG&E's alleged monopoly control of access to Canadian gas and oversubscription of core election.

Accordingly, we issued R.90-02-008 to consider these complaints. In September 1990, in D.90-09-089, we issued revised rules for restructuring to take effect August 1, 1991. That decision approved certain provisions of a settlement which would permit PG&E's noncore customers to arrange for purchases of Canadian gas supplies from A&S producers and to receive firm service over the PGT/PG&E pipelines.

These regulatory initiatives serve as the framework within which we shall review and evaluate parties' respective arguments.

A. Position of PG&E

PG&E defends its Canadian gas procurement strategy as being not only reasonable but highly successful. PG&E asserts that it secured a stable and reliable supply of long-term gas for its core customers, as mandated by the Commission, at prices lower than Southwest spot gas, its only available alternative. PG&E characterizes its policies as being fully in conformance with CPUC policy directives and goals as they evolved throughout the record periods. PG&E points to its success in this accomplishment despite pipeline capacity constraints, high gas demand, and dramatic structural adjustments going on in the U.S. Southwest gas markets. PG&E also contends that Canadian governmental intervention and price discrimination among Canadian producers would have foreclosed its attempts to seek cheaper alternative Canadian supplies. PG&E criticizes DRA/SMUD/TURN as presenting options which are internally contradictory, naive, economically infeasible, and in some cases, detrimental to ratepayers.

B. Position of DRA

DRA claims PG&E, through its affiliates, engaged in various anticompetitive activities aimed at entrenching its monopoly advantage as a gas merchant and thwarting regulatory initiatives aimed at promoting competition. DRA states PG&E offered A&S producers the maximum payment it could sustain based on alternative U.S. supply markets while ignoring more competitively priced gas within Canada. California customers did not share in the lower transportation costs associated with the depreciated PGT pipeline, in DRA's view.

DRA proposes a disallowance of $391.9 million[3] for the 1988-90 record periods. DRA's disallowance is not linked to any single procurement strategy, but rather is intended to illustrate the savings which PG&E allegedly could have extracted under various alternative approaches.

DRA maintains PG&E could have either (1) purchased full volumes of A&S long-term contract gas but negotiated more aggressively for lower prices tied to competitive alternatives within Canada; (2) replaced a portion of A&S contract purchases with spot gas from independent Canadian suppliers; or (3) reduced PGT purchases by PG&E, thereby promoting open access by freeing pipeline capacity for other entities to use. DRA assumes each of these strategies or any combinations thereof equally support the same disallowance figure. DRA's disallowance is computed by deducting the difference between the A&S pool price and the Alberta spot price for the equivalent of 50% of A&S volumes. On this basis, DRA computes the following disallowances for imprudent Canadian gas costs for the 1988-90 record periods:

Year	Disallowance ($ Millions)
1988	$126.2
1989	$125.7
1990	$140.0
Total	$391.9

Source: Exh. 1100

3 DRA unintentionally omitted the month of January in both 1989 and 1990 in making its disallowance calculation. Correction for this omission would increase DRA's total disallowance proposal to $405 million, plus interest.

C. **Position of SMUD**

SMUD is a municipal utility providing retail electric service to more than 450,000 customers in the greater Sacramento area. SMUD's primary interest in this proceeding is as a wholesale customer of PG&E. During the record period, SMUD purchased from PG&E 100% of its natural gas requirements as well as a share of its electric power indexed to PG&E's gas costs. SMUD agrees in broad terms with DRA's criticism of PG&E's failure to exploit competitive opportunities. SMUD believes PG&E followed a "pervasive strategy" to maintain full utilization of the PGT pipeline for the benefit of the A&S pool at the highest price PG&E could pay and still take all of the producers' gas.

Specifically, SMUD concludes that PG&E should have:

- o started making the transition to a free market structure in the mid-1980s;
- o decoupled its UEG purchases from its core procurement;
- o encouraged noncore customers to procure gas independently;
- o systematically reduced A&S's contractual obligations by depletion, attrition, and negotiation until minimum takes were no more than 50% of PGT capacity entitlements;
- o cultivated British Columbia supply alternatives;
- o encouraged producer competition with and within the A&S pool; and
- o fully utilized its own strategic advantages, including control of PGT,in bargaining with A&S producers.

SMUD goes even farther than DRA in its assessment of how aggressive PG&E could have been in driving down its average prices for Canadian gas. While DRA calculates a disallowance based on a split-the-savings approach as described above, SMUD argues that this "compromise" on DRA's part is tantamount to acquiescing to the unnecessary and unwarranted transfer of several hundred million dollars from California consumers to Alberta producers. SMUD proposes that all of the economic rents (i.e., the scarcity value attributable to the PGT pipeline) measured by the price spread between intra-Alberta and A&S pool contract prices be assigned to ratepayers.

SMUD allocates its proposed disallowance among PG&E's core, noncore, and UEG customers. SMUD presents a range of estimated overcharges from $530 million to $660 million associated with alleged imprudent Canadian gas costs, based upon alternate assumptions as to how PGT capacity could have been shared among UEG, other noncore, and core customer classes.

D. Position of TURN

TURN also proposes a disallowance for PG&E's imprudence in procuring Canadian gas, but for different reasons from those of DRA/SMUD. TURN disagrees with the DRA/SMUD thesis that a workably competitive free market for gas sales from Canada would have existed but for anticompetitive actions of PG&E, and that the workings of such a market would have meant lower costs for ratepayers. TURN doubts that a truly free market could have been achieved during the record periods because of the existence of the PGT pipeline capacity constraints on deliveries of Canadian gas to California, coupled with the policy of embedded cost-based pricing for that capacity. Thus, TURN's disallowance is based on PG&E's failure to exercise its actual and potential market power to extract a reasonable contract price in its annual negotiations with A&S producers.

TURN believes that PG&E could have used its leverage as the only holder of firm access to PGT to seek a more equitable division of the economic rents associated with that capacity. The spread between the buyer's alternative supply costs (i.e., the U.S. Southwest supply basin) versus the seller's alternative revenue market (i.e., Canadian spot sales) represented economic value which TURN describes as "rents" attributable to the PGT pipeline. TURN presumes that in negotiations between PG&E and A&S producers, both sides would seek to maximize their share of such rents. While PG&E only captured 10% of these rents, A&S producers captured 90% in the 1989 and 1990 price redeterminations, according to TURN. (TURN offers no opinion concerning the 1988 price negotiations). TURN believes a more equitable outcome would have been for A&S producers to share the rents with consumers on a "split-the-savings" 50/50 basis. TURN thus proposes a disallowance be imposed to the extent PG&E failed to negotiate aggressively to achieve such a result. TURN sponsors no specific price value upon which to compute its 50/50 rent-sharing approach, but defers to DRA on this matter.

E. Position of IPAC/CPA

IPAC and CPA are trade groups whose members are among the Canadian producers who sold gas to PG&E through the A&S pool during the record periods. While IPAC and CPA claim no direct interest in parties' claims that PG&E should be assessed a disallowance, they express concern over alleged mischaracterizations made by DRA and SMUD which portray Canadian producers, the general Canadian producing sector, and Canadian regulatory structures in a poor light. Specifically, IPAC/CPA accuse DRA of engaging in hindsight reinvention of the record period to suit its own agenda for the prospective restructuring of PG&E's Canadian gas supply arrangements.

While generally allied with PG&E, IPAC disputes PG&E's characterization of Canadian producer price discrimination and the degree to which a competitive gas market existed within Canada. To the extent A&S prices were priced above other Alberta sales, IPAC, disputes PG&E's claims that they were due to regional price discrimination or market power on the part of Canadian producers. Rather, IPAC portrays A&S prices as being market-driven and commensurate with the risks assumed in providing a long-term reliable source of supply.

F. Position of APMC

The APMC is the agency of the Province of Alberta which represents the interests of Alberta at regulatory proceedings outside of the province. APMC generally concurs with the views of IPAC regarding the nature of the Alberta gas market, and disputes PG&E's contentions that the regulatory climate and market structure in Canada would have prevented the utility from purchasing a portion of its supplies at spot prices, if it had so chosen.

IV. Standards and Scope of Commission Review of Reasonableness

Over many years of conducting reasonableness reviews, we have identified various standards to guide our review. We discuss herewith these standards as they relate to the scope of our review of the 1988-90 record periods.

A. Jurisdictional Scope of CPUC Review

On May 12, 1992, PG&E filed a Motion for Summary Judgment moving for rejection of the various bases for disallowance of Canadian gas costs presented by parties in this proceeding. PG&E argued that this Commission must reject parties' claims because jurisdiction over such claims lies exclusively with agencies of the federal government who have already approved the supply arrangements which have been challenged in this proceeding. We denied PG&E's motion by D.92-07-078 and its application for rehearing by D.92-10-058. Nonetheless, in its brief PG&E renews its assertion that this Commission is precluded as a matter of law from adjudicating parties' claims in this proceeding. We need not discuss here PG&E's renewal of arguments raised previously and decided in D.92-07-078 and D.92-10-058. However, we will comment upon the new interpretation of D.92-10-058 which PG&E presents in its brief.

PG&E asserts that D.92-10-058 served to considerably narrow the scope of the issues in this case. Specifically, PG&E reads D.92-10-058 as foreclosing our consideration of the reasonableness of the A&S/PGT Gas Sales Contract price or of PGT's FERC-approved rates. As such, PG&E argues that it is not within this Commission's jurisdiction to consider the DRA and TURN arguments that PG&E, directly or in concert with PGT and A&S, could have negotiated a lower price under the existing supply arrangements. Notwithstanding our denial of PG&E's motion for summary judgment, PG&E interprets D.92-07-078 as limiting our review to whether PG&E could have bought imported gas from sources <u>other than from PGT</u>.

Contrary to PG&E's view, in D.92-07-078 we expressly declined to limit our scope of review with respect to any of the disallowance theories advanced by parties, stating:

> "...the objective of [PG&E's] motion was to obtain a summary preclusion of our ability to consider the disallowances recommended...we are <u>not precluded on any ground</u> fairly ascribed to PG&E's motion from permitting that regular evidentiary process from proceeding." (P. 23, emphasis added.)

We reached this conclusion in recognition of the fact that parties' disallowance claims are exclusively based upon the prudence of PG&E's actions, as opposed to those of PGT or A&S. As stated in D.92-07-078, to the extent PG&E actively participated in the A&S producer price negotiations, such actions constituted part of PG&E's purchasing strategy which is properly within the jurisdiction of our review. FERC has expressly deferred to this Commission's jurisdiction over the "purchasing strategy" of a local distribution company (<u>Northwest Alaskan Pipeline Co.</u> 29 FERC ¶ 61,304 at p. 61,638 (1984).)

We conclude that PG&E, as distinct from its affiliate A&S, did in fact play an active and decisive role in directly negotiating with A&S producers. As PG&E's chief policy witness stated:

> "...PG&E is in a market in which major competing energy sources exist, as defined in the international contract. It refers to PG&E's market. PG&E does the commodity rate analysis. PG&E says how it's going to buy its gas for its core portfolio. In that context, A&S was simply carrying out the needs of PG&E's policies in terms of how it bought gas and what prices it needed to be competitive in its market." (Bellenger/Tr. 7789:1-9.)

Thus, to the extent PG&E's actions as a price negotiator may have increased the ultimate costs ultimately charged to PG&E's retail customers, we may properly scrutinize such actions and compare them against other strategies which PG&E might have pursued. The focus of our review is upon PG&E's actions. To the extent we make reference to the actions of its affiliates, PGT or A&S, it is only to provide a context in which to view PG&E's actions and how it could have influenced outcomes differently. We do not make findings in this decision on the reasonableness of PGT's or A&S's actions.

B. Burden of Proof

PG&E bears the burden of proof that its Canadian purchased gas costs incurred during the record period were prudently incurred. PG&E must show that it prudently took advantage of competitive market forces to the extent feasible to extract competitive prices for its customers consistent with our regulatory policies. To the extent PG&E satisfies that burden, it is entitled to recovery of its costs. To the extent it fails to meet that burden, we may disallow recovery of imprudent costs.

PG&E contends that DRA/TURN/SMUD have attempted to place an unfair and unlawful burden of proof upon it--that to avoid a disallowance, PG&E must prove a negative, namely that there were no lower cost outcomes which could possibly have occurred. We do not expect PG&E to prove a negative. We do expect PG&E to accept responsibility for addressing positive evidence purporting to show lower market prices were available relative to the A&S producer pool. Alleged deficiencies in the cases put forth by DRA or other intervenors do not relieve PG&E of its affirmative burden to prove that its actions were reasonable. As we have previously stated:

> "...where other parties challenge the utility's showing such parties have the burden of producing evidence in support of such challenge and in support of adoption of their recommended ratemaking disallowance or adjustment, but the ultimate burden of proof of reasonableness is never shifted from the utility to the challenging parties." (Re Pacific Bell [D.87-12-067] (1987) 27 CPUC2d 1, 145.)

We further elaborated on the burden of proof in D.90-09-088:

> "The burden rests heavily upon a utility to prove with clear and convincing evidence, that it is entitled to the requested rate relief and not upon the Commission, it staff, or any interested party to prove the contrary." (Re Southern California Edison Company [D.90-09-088] (1990) 37 CPUC2d 488, 499.)

C. Avoidance of Hindsight

The determination of the reasonableness of PG&E's Canadian gas costs during the record periods must be based on information known to PG&E's management at the time that procurement decisions were made and must avoid hindsight. We take this charge seriously and have kept it foremost in mind in the course of our deliberations. We recognize, for example, that because of successive schedule deferrals in our Rate Case Plan, we are now faced with reviewing a 1988 record period five years after the fact. Although the passage of time makes a reconstruction of earlier events more difficult, we have striven for accuracy. Moreover, the periods before, during, and since the record periods under review have been characterized by continuing regulatory and market structure changes. We have keyed our review to the contemporaneous environment in which PG&E's decisions were made, even if post-record period developments may suggest a different course of action would have been better.

DRA has raised concerns over the relationship between currently-in-progress restructuring of PG&E's purchase arrangements with Canadian producers and its alleged anticompetitive behavior during the record periods. DRA believes that anticompetitive actions by PG&E during the record periods bear upon the Commission's review and approval of any prospective restructuring arrangements, and in particular, the terms of any ratepayer funding of transition costs related to restructuring. Earlier in this proceeding, we bifurcated our review and relegated prospective restructuring issues to a separate phase in response to PG&E's concerns that concurrent determination of those issues would raise the spectre of hindsight analysis.

D. Role of CPUC Regulatory Policies as Reasonableness Standard

We issued various decisions in rulemaking proceedings providing general prospective policies and goals for gas procurement during the 1988-90 record periods. A key dispute among parties involves the significance of our own role through policies we adopted during the record period in PG&E's decision making.

DRA contends that during the record period PG&E was "slow and unresponsive to Commission directives" (Exh. 1100, pp. 1-5) promoting a more competitive industry structure, and that PG&E's actions in forstalling development of a competitive market were imprudent. By contrast, PG&E argues that it was fully consistent with our policies and directives throughout the record period. In fact, as a matter of fundamental fairness, PG&E contends that its actions should be found reasonable since it was carrying out policies and directives which the Commission as well as other governmental agencies had endorsed or encouraged. PG&E further notes that DRA had prepared an earlier report which found PG&E's

1988 gas purchases to be prudent. Only later did DRA produce a different report (Exh. 1100) alleging imprudence. In PG&E's view, this subsequent DRA report was based upon hindsight.

We examine the nature of Commission policies concerning gas industry restructuring and open access in detail further in the body of this decision. Here, we seek only to lay the overall framework in which our policies are relevant to adjudication of PG&E's prudence. The issuance of specific Commission policies or guidelines during the record periods in no way relieves PG&E of responsibility for justifying the specific decisions it made in implementing these and various policies. As we stated in D.88-03-036:

> "Utilities are held to a standard of reasonableness based upon the facts that are known at the time. While this reasonableness standard can be clarified through the adoption of guidelines, the utilities should be aware that guidelines are only advisory in nature and do not relieve the utility of its burden to show that its actions were reasonable in light of circumstances existent at the time. Whatever guidelines are in place, the utility always will be required to demonstrate that its actions are reasonable through clear and convincing evidence." (27 CPUC2d 525, 527.)

In adopting our new regulatory framework in D.86-12-010, we placed parties on notice that: "Gas acquisitions from affiliated entities will receive the closest scrutiny because of the obvious potential for 'self dealing' at the expense of core ratepayers." (22 CPUC2d 491, 531.)

Moreover, the fact that DRA issued a previous report which concluded that PG&E's gas purchases were reasonable in no way relieves PG&E of its burden of proof. That report was mailed, but never offered into evidence by DRA. The issue of what DRA did or did not know at the time it prepared that earlier report is irrelevant as evidence of PG&E's reasonableness. The relevant issue is what PG&E knew or should have known during the 1988-90 record periods.

PG&E's procurement decisions must be viewed discretely in terms of the changing conditions at each stage of this three-year record period. We must also consider the interlocking cause-and-effect relationship embodied in PG&E's actions. Thus, we must consider not only PG&E's choices, but how outside market forces could or would have responded, and what consequent options would have unfolded for PG&E. Such forces include other potential gas suppliers to PG&E, Canadian regulatory authorities, third party transport shippers, and competing buyers for Canadian gas. We must consider the opportunities PG&E may have exploited had it made different choices earlier at various points during the record periods. Thus, even if an opportunity was closed, PG&E is not necessarily excused if its own earlier choices foreclosed the opportunity.

E. Framework for Evaluating Claimed Cost Savings

Our task in a reasonableness review is to determine whether the actions of utility management "comport with what a reasonable manager of sufficient education, training, experience and skills using the tools and knowledge at his disposal would do when faced with a need to make a decision and act." (D.90-09-088; 37 CPUC2d 488, 499-500.) Our review thus involves scrutiny both of the actions of management and the economic consequences of those actions. To impose a disallowance of costs, we must first find that a utility action was imprudent based upon this criterion. Then we must assess the consequences of the imprudent action as measured in ratepayer harm. Accordingly, in this case, we must measure both the price and volumes of gas which PG&E could have procured at lower costs, if any.

Our framework for analysis of claims that PG&E could have reduced its Canadian gas costs involves the following process. DRA, SMUD, and TURN propose alternative strategies by which they claim PG&E could have reduced its Canadian gas costs. We divide these strategies into two general categories: either (1) continuing to deal exclusively with the A&S pool, but bargaining for a lower price or (2) displacing up to 50% of purchases from the A&S pool with gas from other Canadian suppliers. We must determine what specific actions would have been required for PG&E to implement any strategy. We consider each required action as to feasibility and effectiveness in lowering gas costs.

We conclude in Section V.A. that PG&E's primary option was to deal exclusively with the A&S pool, but to bargain more aggressively for a lower price. We conclude PG&E could have bargained for a lower price based upon more aggressive use of its market power and the threat of displacing a portion of the A&S pool gas with cheaper alternatives.

If the A&S pool had ultimately refused to negotiate a price which took into account competitive market forces within Alberta, PG&E could have positioned itself to procure a portion of its Canadian gas outside of the A&S pool. Accordingly, we consider procurement of gas outside of the pool as a recourse option available to PG&E which could have been pursued if necessary. We consider the feasiblity of procurement for certain volumes outside of the A&S pool in Section V, given alleged impediments as claimed by PG&E, IPAC, and CPA. Even if a given strategy would have produced lower gas prices, PG&E must be found reasonable if impediments beyond its control foreclosed its ability to execute such a strategy.

Assuming that PG&E could have procured alternative Canadian supplies, we then determine what prices would have been reasonable under such alternative procurement. In Section VI, we make this determination based upon competitive market forces and PG&E's relative bargaining power. The criterion of a competitive price must be based upon market alternatives which PG&E realistically could pursue. Following this premise, we develop a framework for assessing a reasonable price for PG&E's Canadian gas purchases.

A key part of our price analysis is to define the market in which PG&E could have procured Canadian gas based on supply alternatives to the A&S pool. Given the range of prices within which gas was sold during the record periods, we assess a bargaining range within which a fair price could be negotiated between PG&E and Alberta producers. Accordingly, we compute an overall savings assuming PG&E had replaced a portion of its gas from the A&S pool with other Alberta gas.

Based upon the overall procurement savings which we develop in Section VI, we consider the reasonableness of PG&E's negotiations with the A&S pool in Section VII. We apply the savings computed in Section VI as a standard against which to evaluate PG&E's negotiations with the A&S pool. On this basis, we conclude that PG&E could have achieved net savings by dealing exclusively with the A&S pool equivalent to what could have been negotiated based upon our analysis in Section VI. The A&S price which would yield an equivalent result to buying from competitors is shown in Appendix D, Column F.

Even apart from the immediate economic consequences, however, we are still interested in the prudence of the utility's actions. As we have previously stated: "The Commission, as the agency charged with oversight and economic regulation of the monopoly utilities, has a legitimate concern not only with the outcomes of the utilities' decisions, but also the process employed to arrive at a particular decision." (37 CPUC2d 488, 499-500.) For example, in this proceeding, certain parties have alleged PG&E engaged in anticompetitive behavior with respect to its transport and procurement contracting practices. This issue is a separate concern to be addressed irrespective of whether or to what extent ratepayers may have been specifically harmed by such behavior during the record periods. In Section VIII, we discuss this further.

We take up the question in the following section of alleged impediments to procuring more competitively priced supplies.

V. Determining Factors Affecting PG&E's Ability to Lower its Canadian Gas Costs

A. Did Contractual Constraints Preclude PG&E From Purchasing Cheaper Gas From Alternative Suppliers?

1. Background

PG&E's purchases of Canadian gas are governed by a chain of contractual relationships through its affiliates. Three levels of contracts provided for PG&E's takes of Alberta gas: (1) individual producer contracts with A&S (collectively known as the A&S producer pool); (2) the International Contract between A&S and PGT; and (3) the Service Agreement between PG&E and PGT. We shall discuss these in turn.

The first link in the contract chain involves contracts between A&S and individual Alberta producers. A&S aggregates and manages a portfolio of supply contracts with numerous Alberta producers under a pool arrangement (i.e., the "A&S pool"). The obligations of individual Alberta producers are guided by the specific terms and conditions of their respective contracts with A&S. One single price is agreed to by all members of the A&S pool through the producer voting mechanism. Individual producers' netbacks vary based upon their respective mix of firm versus flexible-take gas. Although the individual producer contracts with A&S contain various provisions relating to take commitments, parties did not address the details of such provisions. DRA states that the extent of A&S's contractual liability for minimum takes from individual producers is "somewhat hazy" (Exh. 1100, p. 4-15).

In its own internal audit report, A&S noted that its contracts with producers represent unique negotiations resulting in a multitude of differing terms and conditions relating to minimum takes. (Exh. 1100, p. 4-15.)

The second link in the contract chain is the International Contract between A&S and PGT through which A&S sold gas at the U.S./Canadian border pursuant to export licenses and removal permits authorized by the Canadian government and import permits authorized by the U.S. Department of Energy (DOE).

The dispute over A&S gas take commitments centers on the terms of the International Contract between A&S and PGT, and the basis upon which gas takes could be reduced without penalty. The individual A&S producer contracts are predicated upon take commitments contained in the International Contract. The contracting parties' rights and obligations under the International Contract and A&S producer contracts are defined by the terms of renegotiation which became effective in November 1984. This date coincided with the end of Canadian government mandated gas prices. Prior to the renegotiations, the A&S gas take commitment had been up to 90% of licensed volumes, based upon a price which was inflexibly tied to alternate fuel oil prices.

Since U.S. southwest gas sources were cheaper prior to November 1984 than A&S contract gas, A&S producers were losing sales to U.S. competitors. Thus, to rectify its competitive imbalance relative to U.S. supplies, the A&S producers agreed to relieve A&S of a large share of its accumulated TOP obligations and to reduce the required ongoing minimum take. As part of the renegotiations, the minimum take under the International Contract was reduced from 90% to 50%. The remaining 50% was subject to an "equitable take provision" requiring PGT to allocate PGT's remaining purchases (above the 50% minimum level) to A&S in proportion to its total gas requirements, to the extent the A&S gas was competitively priced with supplies in PG&E's consuming market.

(Exh. 1505/Tab 3-p. 10.) Thereby, a competitive pricing standard replaced the NEB-government-mandated prices tied to fuel oil.

The third link in the contract chain involves PG&E's take commitments to PGT, governed by PG&E's FERC-approved cost of service tariff with PGT (the Service Agreement). Under the Service Agreement, A&S gas is transported from the U.S./Canadian border to the California/Oregon border for sale to PG&E. Shortly after the 1984 International Contract renegotiation, PG&E inserted a provision in its Service Agreement stating that PG&E would purchase gas from PGT "on an equitable percentage basis with its purchases of gas from other suppliers." PG&E's Service Agreement included a 50% minimum bill. In PGT's January 1990 General Rate Case (GRC) decision, FERC ordered PGT to remove the 50% minimum bill from PG&E's Service Agreement. Thus, PG&E's takes under its FERC tariff were predicated on the successive chain of contracts leading back to the A&S producer pool.

2. <u>Positions of Parties</u>

DRA/SMUD interpret the 1984 renegotiated International Contract as permitting PGT to reduce its takes to a minimum of 50% without incurring penalties or breach of contract. Thus, they believe PGT legally could have curtailed purchases of 50% of A&S contract volumes since in their view this gas was not competitively priced. The reduced takes would have freed up 50% of PGT's pipeline capacity which could then be used by PG&E and/or its noncore customers for spot purchases and transportation of customer-owned gas supplies. Even assuming that under netback pricing PG&E was required to take full A&S volumes, DRA believes that PG&E/A&S could have legally abandoned the netback pricing provisions underlying its take commitments in October 1988 and again in October 1990 when the provision would otherwise have expired. A&S would then have been able to negotiate individually with each producer for competitive market-based prices. Instead, PG&E renewed these contract provisions. We address the prudence of continuing this option versus going to one-on-one negotiations in Section VII.

PG&E argues that it was precluded from taking less than full contract volumes of A&S gas by the terms of contractual commitments with A&S producers. PG&E contends that the 50% take level was intended only as an extreme minimum in the event that A&S pricing was not competitive in PG&E's market. PG&E/IPAC characterize the "equitable purchase policy" applicable to volumes above 50% as the quid pro quo for "relaxed minimum purchase obligations that were implemented in November 1984 along with market oriented pricing" (Exh. 1505, Part 2; Tab 11). A&S producers relied heavily on the take commitments of PG&E (through the A&S/PGT International Contract and the PGT/PG&E Service Agreement) to provide financial returns on which A&S producer investments were predicated. IPAC (Anderson) states that A&S producers committed significant financial resources to explore and develop gas reserves based upon the its contractually supported agreement with A&S to take gas at full contract volumes. Since A&S gas was priced below U.S. Southwest gas levels during each of the record periods, PG&E argues that it was competitive with PG&E's alternatives and thus had to be taken at full volumes.

PG&E/IPAC argue that the 1984 contract renegotiations reflected government policies both in the U.S. and Canada to promote competitive pricing and that these policies were the basis underlying gas export arrangements. Likewise, the U.S. DOE adopted a similar policy. PG&E believes the NEB Gas Export Policy "effectively required exporters to adopt a netback pricing mechanism." (Opening brief, p. 93.) PG&E/IPAC argue that DRA's recommendation that PG&E procure gas based upon Alberta spot prices is directly contrary to the standards for competitive pricing of gas imports adopted by the U.S. DOE. IPAC notes that the DOE has consistently approved the long-term imports by PGT for PG&E under its International Contract with A&S.

PG&E argues that the pricing based upon competing U.S. supply alternatives was in conformance with the netback pricing policies "institutionalized" under the Alberta Natural Gas Marketing Act (NGMA) of 1986 by the Province of Alberta. (Exh. 1025, p. 4-18;4-22/25). PG&E contends that the 1986 enactment of the NGMA effectively gave exporters no practical alternative to netback pricing.

IPAC contends that Commission adoption of DRA/SMUD's proposed disallowance would contravene the principle of the sanctity of contracts and would constitute impermissible regulatory interference with freely negotiated contracts.

3. <u>Discussion</u>

Parties' dispute over contract obligations is complicated by the fact that PG&E did not buy directly from Canadian producers, but bought through an affiliate chain of contracts involving PGT and A&S as intermediaries. We recognize that PG&E's options in procuring sources of Canadian gas were influenced by the chain of contractual commitments under which it purchased A&S gas. Our inquiry in this reasonableness review, however, is focused on PG&E's obligations as opposed to those of its subsidiaries we do not regulate. As we noted in D.92-02-042, where we addressed the relationship of PG&E's contractual obligations relative to its affiliates:

> "The FERC, however, has refused to require PG&E to purchase gas from PGT and its affiliate, Alberta and Southern Gas Company, Ltd. (A&S), notwithstanding A&S' and PGT's contractual commitments. On January 24, 1990, the FERC found PGT's minimum bill was 'unjust and unreasonable' notwithstanding PGT's claims that its minimum bill was a necessary component of its contractual relationship with the Canadians. (See <u>Pacific Gas Transmission Company</u> 50 FERC ¶ 61,067, pp. 61,131-61,132 (1990).)
>
> "...If we could be required to allow PG&E to monopolize access on the PGT pipeline due to

> contracts entered into between PG&E's unregulated affiliate and others, our ability to protect the public from monopolistic practices would be undermined. Section 761 of the California Public Utilities Code, however, provides the Commission with authority to regulate the practices and services of public utilities to ensure that such unjust and unreasonable practices do not occur." (p. 13.)

While we stated this principle in the context of our capacity brokering order in 1992, our obligations under Section 761 were equally applicable throughout the 1988-90 record periods. Accordingly, even if it were true that A&S or PGT were obligated to take full contract volumes under their respective contracts, this would not of itself justify passing such costs through to PG&E ratepayers if unreasonable anticompetitive practices were involved.

We conclude, however, that PGT's contractual commitments with A&S producers under the International Contract did not compel full A&S contract volumes takes unconditionally. The key to understanding the take limitations under the International Contract is a proper interpretation of (1) the equitable take provisions and the circumstances under which equitable takes above the 50% minimum were required and (2) the competitive pricing provisions under which contract prices were determined. As IPAC concedes, the equitable take policy incorporated into the International Contract "placed the burden upon A&S producers to provide a competitively priced product, in order to receive the full benefit of the original take commitments." (Exh. 1402, Tab 1; pp. 18-19.) So to determine the extent of contractually required A&S gas takes, we must consider whether the burden was satisfied that the "equitable take" volumes met the competitive pricing requirements under the International Contract. If a competitive price for A&S gas could not be mutually negotiated, as provided by the contract, PGT (and PG&E) would not be contractually bound to take volumes exceeding the 50% minimum.

The question is: What is a "competitive" price under the International Contract? PG&E/IPAC/CPA base their definition of a competitive price on the concept of netback pricing. The definition of netback pricing as applied by the NGMA does not mandate any specific price index against which Alberta prices shall be fixed. Under the NGMA, netback gas merely refers to gas sold by a producer to other than an end-user, where the price is determined by a formula relating to the resale price. But there is no specific reference as to how the resale price is to be determined. PG&E's chief policy witness, Bellenger, distinguished the NGMA formal definition from PG&E's conception of netback pricing as used in the International Contract. Bellenger states that under the International Contract netback pricing is:

> "not a specific legal requirement, but rather a mechanism by which market pricing can occur. So when we look at the international contract, we don't see the terms "netback pricing," but we do see the term "competing with major energy sources in PG&E's market." (Tr. 7488:6-25.)

PG&E's witness Harrison further drew the distinction that "the voting requirement is derived from the [NGMA] but the netback arrangement exists by virtue of the contractual arrangements between the parties. (Tr. 8827:12-19.)

Essentially, the only thing that the NGMA's netback pricing "institutionalized" was an officially sanctioned means by which the A&S producer pool could approve A&S's downstream price to PGT and to distribute net revenues received by A&S among the members of the pool. (Tr. 7540:27-7541:12.) The NGMA Section 8 (1)-c defines "netback pricing" as a price "under which the actual price payable by a shipper...is calculated wholly or partly by reference to a price or prices payable to the shipper on the resale of gas by him..." (Statutes of Alberta, Chap. N-2.8 (1986); Exh. 1419). Thus, under the NGMA netback pricing concept, a producer "nets back" revenues after deducting transportation and other costs incurred between the wellhead and the downstream place of sale.

As pointed out by APMC, the NGMA did not require the contractual adoption of a netback pricing arrangement as applied by parties to the International Contract. As Bellenger conceded, "netback pricing" linked to U.S. southwest prices was "not a specific legal requirement" (Tr. 7488:6-25). It was entirely at the option of the producers, and a contractual matter between the producer and aggregator. Producers could choose alternate pricing arrangements such as fixed prices if they wished. (APMC brief, pp. 7-8.)

As applied in the International Contract, the negotiated price was to be referenced against the prices in PG&E's consuming market area. The two necessary elements in defining prices in PG&E's consuming market are: (1) the service territory perimeters making up PG&E's consuming market and (2) the supply basin(s) serving that consuming market. The supply source need not be located within the perimeters of the service territory. In justifying A&S prices, PG&E/IPAC identify the supply basins serving PG&E's "consuming market" with out-of-state U.S. southwest gas throughout the record periods. Yet, nowhere in the language in the NGMA nor in the International Contract is there any provision restricting the geographic region constituting the supply basin location serving PG&E's "consuming market."

As noted by APMC, "there was no legislative or regulatory requirement as to where the competitive market interface should be." (APMC Brief, p. 9.) We find no basis to read into the International Contract restrictions not explicitly there. In this manner, the negotiated price could apply to a broader range of market alternatives than simply U.S. southwest prices. The downstream price against which revenues would be netted back could be referenced to Canadian as well as to U.S. southwest alternatives. In support of this view, SMUD's expert witness testified: "The pricing provisions of the International Contract...do not dictate any particular price or pricing methodology, nor do they preclude taking account of the market value of gas expressed in alternative Canadian transactions in establishing a price (Exh. 1200, p. 22/23; also Tr. 4727:6-4729:11; Tr. 4731:18-4732:18).

When the International Contract was amended in 1984, because imported A&S gas was priced higher than PG&E's U.S. domestic alternatives, the focus of competition was with U.S. supply sources, not other Alberta producers. While A&S prices remained higher than U.S. southwest prices, the U.S. southwest supply basin remained the appropriate locus of PG&E's consuming market alternatives. Once A&S prices dropped below U.S. southwest levels, however, the locus of PG&E's marginal competitive market logically would also shift. Once this shift occurred, PG&E need no longer passively accept as a foregone conclusion that U.S. southwest gas must remain its only permissible competitive alternative to A&S gas. To the extent other supply options within Canada could offer competitive alternatives to A&S gas, those alternatives would logically enter into the definition of PG&E's consuming market alternatives.

Moreover, PG&E, itself, in its negotiating sessions with A&S producers during the record periods portrayed "netback pricing" as encompassing a much broader spectrum of supply options than simply U.S. southwest gas. As illustrated on Figure 3-G of Exhibit 1008, PG&E even included Alberta market prices outside of the A&S pool as one of the relevant factors in assessing PG&E's "netback price" indicators. (Tr. 7997:6-7998:22). PG&E's witness Seedall characterizes the contractual pricing provisions under the International Contract not as limited simply to U.S. southwest prices, but as being subject to:

> "[a] whole array of pricing measures. And that was one of the benefits of having this particular pricing structure established in the

> A&S/PGT gas sales contract that was established in 1984. <u>It was a very broad based market measure that allowed the company to negotiate with a whole menu of options</u>. And, in fact, the producers were concerned about the way this was set up in '84 because ...we could have such a wide diversity of measures. They would much preferred to have it tied to a single index and not be able to adjust based on changing market conditions." (Emphasis added.) (Tr. 7998.)

PG&E also takes credit for negotiating A&S prices which it characterizes as being significantly below U.S. southwest prices. Thus, PG&E's own characterizations indicate there was no rigid contractual restriction limiting A&S prices to U.S. Southwest prices or precluding reference to Alberta market data.

Yet, PG&E now criticizes DRA's and SMUD's focus on alternative prices within Canada as a form of "supply basin competition." PG&E asserts that the prices which other Alberta producers received among supply basins within Canada are not relevant to PG&E's consuming market alternative. PG&E asserts that the proper focus for measuring the competitiveness of its Canadian purchases is upon alternatives available at PG&E customers' burner tip. Thus, PG&E dismisses prices of non-A&S Alberta supply basins as being indicative of its own market options since they reflect prices paid in other markets bearing no relationship to PG&E's consuming market. IPAC supports PG&E's position concerning burner tip competition, arguing further that DRA's intra-Alberta pricing standard would have been inconsistent with the standards adopted by the U.S. Department of Energy (DOE) for competitive pricing of gas imports and the standards adopted by this Commission.

We find nothing logically inconsistent in considering prices for Canadian gas outside of the A&S pool as a factor in determining burner tip competition with respect to the International Contract. We acknowledge the validity of burner tip prices for evaluating competition in the context of the "equitable take" clause in the International Contract. To compare burner tip prices, however, we must define the supply source potentially available at the burner tip. The fact that gas supplies outside of the A&S pool from other Canadian producers were not purchased by PG&E does not prove other sources of cheaper Canadian gas were not potentially available to serve PG&E customers at the burner tip.

The principle of intra-Canadian competition is consistent with our past pronouncements concerning burner tip competition. Our endorsement of burner tip alternatives as the standard against which to judge the competitiveness of PG&E's Canadian gas purchases was designed to promote the lowest, most competitive prices for retail customers. As we stated in D.87-05-069:

> "We encourage competition at the burner tip, competition for the provision of fossil fuel energy to those ultimate consumers who have been blessed with market options. That is the competition which matters most for the health of California's gas industry." (24 CPUC2d 368, 400.)

We believe PG&E/IPAC have misapplied our burner tip policy. Burner tip competition merely refers to the relevant point during gas transit at which prices for delivered gas are to be measured competitively. We never intended for burner-tip competition to limit the range of supply basin options competing at the burner tip. Neither did we intend that burner tip competition be used to protect Canadian producers from competition among each other. We recognize that an arbitrary comparison of different Alberta supply basin prices does not necessarily measure PG&E's potential options as a buyer. There must be evidence that PG&E could have reasonably accessed a given supply source at a given price or have used the threat as leverage against A&S producers. Yet, PG&E should have aggressively stimulated competition at the burner tip wherever it perceived an opportunity for lower prices, including among Canadian producers.

In our view, the use of Alberta supply basin price data to stimulate lower burner tip prices is not supply basin competition. It is aggressive burner tip competition. Burner tip competition does not stop at the Canadian border.

Our perspective is consistent with the U.S. DOE import policies concerning competitive pricing. The U.S. national policy articulated in the DOE guidelines (49 Fed. Reg. 6684 (1984) was to let the market, not the government, determine the price and other terms of gas import agreements.[4] In carrying out this policy, the ERA permitted competing imports of Canadian spot gas sources into the California market notwithstanding PGT's request for assurances that its long term supply arrangement would not be threatened.

We previously cited examples of this policy in D.92-10-058, our Order Denying Rehearing of D.92-07-078. For example, in Dome Petroleum Corporation (1985) 1 ERA ¶ 70,601 at p. 72,417, the ERA granted Dome Petroleum Corporation (Dome) blanket import authorization to make spot sales into California and elsewhere because it would, "foster the new and positive competitive forces which the applicant's import would bring to the marketplace." Although PGT intervened and wanted assurances that its long-term supply arrangement would not be adversely affected, the ERA noted that it had

> "made a decision on PGT's concerns when [the ERA] authorized the blanket import arrangements requested by Cabot Energy Supply Corporation, Northwest Alaskan Pipeline Company, and Tenngasco Exchange Corporation and LHC Pipeline Company. In those orders, we found that there was no need for the government to protect long-term, firm imports against competition from

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4 The DOE initially exercised its import authorization through the Economic Regulatory Administration (ERA). Subsequently, the DOE transferred this authority to the Office of Fossil Energy (OFE). (54 Fed. Reg. 11436 (1989).) For the sake of convenience, we will hereinafter use "ERA" to refer to either the ERA or the OFE.

> short-term spot imports. Long-term suppliers have options available to meet such competition which they can exercise without government assistance or interference." (Id. at p. 72,417.)[5]

The ERA made similar determinations in the numerous other decisions granting blanket import authorization to others to import Canadian spot gas into California. (See D.92-10-058 Order Denying Rehearing of D.92-07-078, pp. 13-14 for a listing of additional ERA citations.)

The DOE did not view full takes under the International Contract as a foregone conclusion. It was precisely because of the flexibility underlying the minimum take requirements negotiated into the International Contract in 1984 that the DOE found the agreement to be in the public interest. As the ERA noted:

> "The substantial reduction in PGT's take or pay obligations, the elimination of its minimum physical take obligations, the reduction in the price of the Canadian gas imported by PGT, and the flexibility provided by the semi-annual review and redetermination provisions amply demonstrate that PGT's import arrangement is competitive and market-responsive..." (Pacific Gas Transmission 1985 1 ERA ¶ 70,591, at p. 72,386).

If we were to simply interpret the 50% minimum take as PG&E and IPAC propose, that would inappropriately trivialize the reduced minimum take clause negotiated in 1984 and ignore the ERA's own basis for agreeing to those terms. We thus reject the notion that Canadian market alternatives are irrelevant in measuring burner tip competition applicable to PGT's "equitable take"

5 In Dome Petroleum Corporation, 1987, 1 ERA ¶ 70,735, the ERA extended for two years Dome's blanket authorization and increased the volume (up to 200 Bcf) for Dome to import for spot market sales in the United States, including California.

obligations. In a reasonableness review, we must consider not merely what happened during the record period, but also what would have happened had missed opportunities been pursued. Accordingly, the proper reference for burner tip competition includes not only U.S. Southwest supplies, but <u>any</u> valid alternative which PG&E could have procured, including Canadian supplies outside of the A&S pool.

4. <u>Conclusion</u>

In summary, we find nothing in the International Contract which precluded reductions in takes down to the 50% minimum in the event a competitive price was not offered by the A&S pool. The obligation to take more than 50% was contingent on the A&S pool's willingness to meet a competitive price. Yet, if (1) lower-priced Canadian supply alternatives could have been procured for certain volumes beyond the 50% minimum take and (2) A&S producers had refused to match those lower prices, then A&S gas would have been uncompetitive with PG&E's burner tip alternatives for those volumes. Under such a scenario, had PG&E pursued alternative volumes, it would not have abrogated the International Contract. On the other hand, we conclude that had A&S producers matched such alternatives with an equal or lower bid, they would have been legally entitled to full takes under the equitable take provisions.

In order to identify PG&E's realistic alternatives to the A&S pool for the "equitable take" volumes under long-term contracts, we must determine to what extent Canadian producers in general and A&S producers, in particular, either (1) did--or could have been induced to--compete against each other in price (i.e., intra-regional competition) or (2) competed only against U.S. suppliers (i.e., interregional competition) but not against each other.

B. Take-or-Pay (TOP) Liabilities Incurred Through A&S Contract

1. Position of DRA

DRA contends that another reason A&S purchases were kept at maximum levels through the record periods was to recover TOP liabilities with A&S producers created by overcontracting gas supplies during the 1970s and 1980s. The extent of A&S's contracting was not limited only to supplying PG&E's demand, but also included procurement for sales to Canadian utilities and other markets in Canada and the U.S. DRA believes that PG&E shielded A&S from the business risk of declining sales in other markets by shifting the liability for all costs associated with A&S's TOP liabilities to PG&E ratepayers. According to DRA, the method which A&S used to recover its TOP liabilities kept the PGT pipeline full with A&S gas supplies. DRA contends that instead of pursuing a course of open access to competing suppliers, PG&E maintained monopoly control of its PGT pipeline by giving undue preference for supplies through A&S to make up TOP liabilities, leaving little capacity available for competing suppliers.

To have reduced A&S takes would have at least delayed the ability of A&S to work down its TOP liability according to DRA.

DRA cites three main reasons why the TOP liabilities were incurred. First, back in 1971, A&S had contracted for an additional 200 million cubic feet per day (MMcf/d) of gas to sell to PG&E, without conditioning this commitment on obtaining necessary export licenses. When the NEB denied the export license, A&S was left with the excess gas it could not sell. Second, A&S contracted for gas supplies to sell to Alberta customers. In 1975, A&S lost several of these customers who were able to purchase cheaper supplies directly from Alberta producers. Third, in the early 1980s, to take advantage of more competitively priced gas sources in the U.S., PG&E reduced its gas takes from the A&S producer pool to minimum levels. TOP liabilities were triggered when reduced gas takes by A&S fell below the 90% minimum take level specified in its supply contracts. As a result, PGT incurred TOP liabilities under the International Contract. A&S, in turn, incurred additional TOP liabilities with its producers.

Prior to 1984, the International Contract required that contracted gas be taken at a 90% level or else be paid for. Between July 1980 and October 1984, A&S and PGT negotiated various temporary reductions in minimum TOP obligations in the International Contract from the original 90% down to 60% for the last 10 months of that period.

In conjunction with these and other amendments to the International Contract discussed above, A&S and PG&E/PGT negotiated a revised agreement with A&S producers for recovery of past TOP liabilities. As a result of the negotiations, PG&E amended its Service Agreement with PGT and the International Contract between PGT and A&S in November 1984. Concurrently, A&S agreed with its Alberta producers to reduce its TOP liability to 25% of the amount otherwise due. This reduced the A&S TOP liability from 988 billion cubic feet (Bcf) down to 299.9 Bcf. PGT was responsible for 85.9 Bcf of the total, or $176.6 million (Canadian $). While the agreement eliminated the TOP requirement prospectively from A&S producer contracts, it specified provisions for recovery of past TOP liabilities which were tied to the daily contract quantity (DCQ) under the current A&S producer contracts. PG&E retained a 50% TOP obligation that still allowed direct pass-through via PGT's "cost-of-service" tariff provisions which were not altered by Order 380.

These provisions for recovery of past TOP liabilities were structured so as to preclude any competition for sales to A&S, according to DRA. A&S's take levels for the preceding contract year were required to exceed 60% of the DCQ and to have satisfied its minimum take obligations in the current contract year. Once those conditions were satisfied, A&S would be entitled to recover at least 14.4% but no more than 16.8% of its prepaid gas. During

1988-90, through takes of A&S gas, PG&E recovered $239 million (Canadian $) in such prepayment liabilities.

Another significant factor affecting PGT's TOP liabilities was the issuance of FERC Order 380 in May 1984. FERC Order 380 eliminated "minimum bill" provisions in U.S. interstate pipelines' sales tariffs which had previously required local distribution companies (LDCs) to take a contracted amount of gas supplies or else pay a penalty. This change freed LDCs to purchase more competitively priced gas on the U.S. spot market without having to pay for pipeline companies dedicated gas supplies unless actually purchased. It also left pipelines such as PGT with potential TOP liabilities with producers.

DRA contends that PG&E was "less than enthusiastic" in its response to FERC Order 380. PG&E/PGT jointly sought an exemption to Order 380 for its Canadian gas purchases. FERC Order 380-C rejected PG&E/PGT's argument that the PG&E/PGT/A&S contract chain warranted exemption.

2. <u>Position of PG&E</u>

PG&E disputes DRA's characterizations both of its past contracting practices and the reasonableness of TOP settlements negotiated in 1984. PG&E takes issue with DRA's charge that PG&E ratepayers bore risks and costs associated with A&S contracting of supplies to serve non-PG&E markets. PG&E points out that A&S's domestic Canadian sales were extremely limited. While A&S did evaluate whether any sales opportunities existed as a contingency against declining PG&E sales, PG&E characterizes any such actions as merely complementing A&S's obligation to PG&E, not as expanding its operations.

PG&E defends A&S's contracting for an additional 200 MMcf/d in 1971 as providing a contingency against supply shortages which were an industry-wide concern during the 1970s. The NEB refused to grant export authorization for the 200 MMcf/d because it was not satisfied that its 25-year reserve surplus test could be met.

According to PG&E, A&S did not contract for additional gas supplies during 1975-85, as DRA claims, except for small quantities required by Alberta conservation laws. DRA's conclusion assumes that the "contract date" specified in all A&S gas purchase contracts reflects the time at which A&S first contracted for the underlying reserves and related DCQ. Yet, the contracts created and signed between 1975 and 1985 reflected various administrative changes, but did not increase the reserves under contract or A&S purchase obligations.

PG&E further defends its response to FERC Order 380. As stated its the August 1983 Notice of Proposed Rulemaking (NOPR) which ultimately led to Order 380, FERC sought to determine whether pipelines with minimum commodity bills should charge customers for variable costs not resulting from serving such customers. PG&E/PGT interpreted this Notice as not applicable to PGT since its cost of service tariff inherently precluded such charges. Yet, the final Order 380 differed from the NOPR in that it banned recovery of purchased gas not taken, rather than simply variable costs not incurred. While the PG&E/PGT Service Agreement had no minimum bill, it did have minimum take and TOP provisions which were mirrored in the A&S/PGT contract. Thus, PG&E believes it was reasonable to seek clarification from FERC as to whether PGT could continue to flow through to PG&E the principal amount of any A&S TOP liability incurred through reduced PG&E takes. In Order 380-C (issued October 31, 1984), FERC rejected PG&E/PGT's arguments concerning minimum take provisions. FERC further stated in the Order that its provisions did not apply to the A&S/PGT International Contract.

Thus, PG&E describes its response to FERC Order 380 as simply an attempt to clarify that PGT's cost of service tariff was appropriate due to the PGT/PG&E affiliation, and to ensure that the recently negotiated TOP settlement benefits were preserved.

PG&E contends that its strategies for handling of TOP liabilities were in the best interests of its ratepayers. PG&E believes its resolution of TOP in 1984 wound up being costless for PG&E's ratepayers. The PGT pipeline would have been full of A&S gas in any event because it was the least-cost alternative for ratepayers, according to PG&E. PG&E argues that its recovery of prepaid gas was not significantly affected by the full pipeline volumes since TOP recovery would have occurred in essentially the same timeframe had the throughput on PGT been up to 300 MMcf/d less than the actual full PGT volume. Thus, PG&E asserts that it had no motivation to increase throughput on PGT in excess of 700 MMcf/d to recover prepaid gas.

PG&E characterizes the TOP arrangements as renegotiated in November 1984 as being prudent and in ratepayers' interests. PG&E cites the main benefits as being (1) to shield PG&E's customers from $176 million of past liabilities and potential future liabilities related to the A&S PGT Contract; (2) to reduce minimum take levels and reduced TOP levels to 50%; and (3) to secure a major competitively priced gas supply for California. By comparison to the A&S settlement, PG&E contrasts the much more difficult and litigious treatment of subsequent TOP costs in the El Paso Natural Gas Company (El Paso) case.

3. <u>Discussion</u>

Parties' dispute concerning PG&E's treatment of A&S liabilities involves the issues: (1) To what extent were PG&E's takes of A&S gas constrained by avoidance of TOP liabilities? and (2) To what extent should ratepayers bear responsibility for A&S take commitments associated with makeup of past TOP liabilities?

In addressing the procurement constraints imposed by A&S TOP liabilities, a distinction must be drawn between TOP liabilities incurred by A&S versus those attributable to PGT. A&S

committed itself to TOP liabilities with the producer pool to supply Canadian markets in addition to its requirements to supply PGT's demand. During the contract years 1977-1985, A&S paid $528 million (Canadian) in TOP liabilities to Canadian producers. Of this amount, PGT paid A&S $176 million (Canadian) in TOP liabilities for gas not taken from 1982 through 1984 under the International Contract.

The TOP liabilities incurred by A&S to service markets other than PGT are not the responsibility of PG&E's ratepayers. PG&E, itself, disclaimed control over the purchase commitments of A&S and did not consider the A&S take commitment to be a PG&E commitment. (Tr. 8200-8201). The only TOP liabilities which were incurred to secure supplies for PG&E's ratepayers were those of PGT.

PGT's TOP liabilities were originally incurred during the early 1980s in the interests of securing adequate gas supplies to serve PG&E's ratepayers. PGT's subsequent reductions in takes of A&S gas during the early 1980s were likewise in PG&E's ratepayers' interests to the extent the resulting TOP liabilities gave PG&E the flexibility to substitute cheaper gas. We find no evidence of imprudence by PG&E in its response to FERC Order 380 and its subsequent efforts to negotiate with Canadian producers for a restructuring of its TOP and minimum take obligations in 1984. Accordingly, to the extent that PGT's TOP liabilities were incurred to service PG&E ratepayers, it is reasonable to take them into account in assessing PG&E's ability to reduce takes of A&S pool volumes.

As illustrated on Attachment 3.1 of Exhibit 1103, makeup of past TOP liabilities began in 1987. Such makeups were applied first in order to PGT's share of TOP liabilities. By January 1989, PGT had made up all of its past TOP liability. Thereafter, makeup of the A&S/producer TOP liabilities began. As noted on Attachment 3.1, an average 700 MMcf/d minimum take level was required to makeup all of the A&S/producer TOP liabilities before the expiration of the producer contracts in 1993. Yet, at a reduced take level of only 600 MMcf/d, PGT's share of TOP liability could have been fully made up within four years.

Although PGT actually made up its TOP liabilities by January 1989, this was based upon full PGT pipeline capacity takes of A&S gas during 1988. If 1988 A&S takes had been reduced to only 600 MMcf/d, then the makeup period for PGT TOP liabilities would have taken four years from 1987 according to Attachment 3.1. Accordingly, for purposes of determining the minimum take from the A&S pool required to make up past TOP liabilities, we shall use the average figure of 600 MMcf/d for each of the record periods. At this take level, PG&E would have avoided any TOP liability which might otherwise be charged to ratepayers and would retain some residual bargaining leverage by offering A&S producers some core elect load above the 50% minimum take level. Although A&S would not be able to make up all of its TOP liabilities at a minimum take below 700 MMcf/d take level before contract expiration in June 1993, this is not relevant in considering the liabilities which PG&E ratepayers should bear.

We find that ratepayers benefited from the 1984 renegotiations to the extent that TOP liabilities were reduced to 25% of prior levels. This provision was an integral part of the overall negotiations which also resulted in the reduced minimum take requirements of 50% upon which DRA has predicated its disallowance. If we are to accept the 50% minimum take amendment to the International Contract to be prudent, then it is consistent to find that the TOP stipulation was likewise prudent. We conclude that ratepayers did not bear any extra cost for make up of TOP volumes beyond the uniform commodity price paid for A&S gas as referenced against U.S. Southwest alternatives. A&S producer revenues were reduced on a one-for-one basis to pay off the principal amount, while all carrying charges on the A&S long-term contracts were paid by a reduction in producer netbacks.

It was reasonable that A&S producer volumes be taken to make up such TOP liabilities as long as they were competitively priced. We agree with DRA that it would be imprudent to charge ratepayers for A&S gas simply to protect shareholders from TOP exposure. Yet, we believe that ratepayers benefited as well from PG&E's takes of A&S gas, at least up to the 600 MMcf/d level. PG&E could not turn to competing alternatives to A&S gas in this amount without triggering TOP penalties. Ratepayers avoided paying for such TOP liabilities as a result of A&S pool purchases up to 600 Mmcf/d.

The impact of TOP liabilities was an appropriate consideration in PGT's ultimate decision about the level of A&S pool procurement relative to alternatives. We address the issue of overall takes of A&S gas relative to alternative supplies in Section VI.

C. PGT Transport - Did PG&E Prudently Make Use of the Scarce Capacity?

1. Background

Parties dispute PG&E's decisions concerning options for gas transport over the PGT pipeline during the record periods. The PGT pipeline provided the sole transport link connecting PG&E's consuming retail gas market with the gas supply basins of Canada, principally within Alberta. Thus, control of transport access on PGT was vital to any strategy for procuring alternative Canadian supplies. It was also important in terms of providing PG&E bargaining leverage with the A&S pool.

Among the most significant FERC restructuring policies to promote open access were orders pursuant to Section 311 of the NGPA and FERC Order 436. Prior to enactment of the NGPA in 1978, federal rules had been in place providing for the transport of gas over interstate pipelines. Specifically, under Section 7(c) of the

Natural Gas Act (NGA), a party wishing to transport gas had to apply for a Section 7(c) certificate for each individual transportation agreement. This procedure required separate filings and hearings for each transportation contract.

The enactment of the NGPA in 1978 lifted the requirement for individual Section 7(c) certificates for intrastate pipelines or LDCs. Under Section 311 of the NGPA, FERC could authorize, by rule or order, any interstate pipeline to transport gas on behalf of any intrastate pipeline or LDC, all without the need for a Section 7 certificate. FERC did in fact issue such a rule which was codified as 18 CFR Ch. I, Section 284.102. Advance FERC approval was not required. Where transport capacity was limited, as in the case of the PGT pipeline, gas shipments could be made under Section 311 only to the extent that pipeline capacity was not already being used by another party with a higher priority entitlement.

FERC Order 436, issued in 1985, was further intended to promote open access. Order 436 replaced the requirement for individual Section 7(c) transport certificates with a "blanket" certificate, authorizing a pipeline's transport services generally, and set only ceiling and floor rates that the pipeline could charge for transportation. In return, any pipeline seeking a blanket certificate had to agree to become an "open access" transporter. Accordingly, it had to transport gas owned by anyone who requested transportation on a first-come, first-served basis, even though such transportation would compete with transportation of the pipeline's own sales gas.

2. <u>Positions of Parties</u>

PG&E asserts that it was foreclosed from purchasing alternative Canadian supplies because there was essentially no available transport capacity on the PGT pipeline. During the record period, virtually all the capacity of the PGT pipeline was controlled by A&S and utilized in delivering gas to PG&E purchased under long-term contracts with A&S suppliers. No extra capacity was available for other gas purchases from independent Canadian suppliers. This capacity constraint effectively precluded PG&E from taking Canadian gas outside of the A&S contracts. PG&E further dismisses DRA/SMUD's presumed options for using PGT pipeline transport rights to procure alternative Canadian supplies as being either impractical or detrimental to core customers.

PG&E's ability to reduce sales to noncore customers was effectively constrained by the large core election customer base subsequent to May 1, 1988. Since such a large share of noncore customers had elected into the core, there was little capacity left for independent noncore transport. While PG&E concedes that open access was an important goal, it argues that open access was subordinate to the goal of protection of the core. PG&E contends that core election was endorsed by this Commission as a key means of protecting core customers in the implementation of our May 1, 1988 restructuring program. PG&E, CPA, and IPAC argue that DRA/SMUD mischaracterize the reasons behind our 1986 industry restructuring. PG&E points to the primary concern of the Commission as being protection of core customers from adverse impacts of uneconomic bypass by noncore customers, not open access.

DRA/SMUD contend that PG&E maintained a pervasive strategy of restraining competition by keeping the PGT pipeline full with gas purchased from A&S under long-term contracts with a pool of Alberta producers. DRA/SMUD contend that PG&E paid the highest price for A&S gas it could sustain and still sequence it preferentially ahead of its other gas supplies. As such, virtually no spare PGT capacity was left for competing suppliers to gain access to PGT transport. PG&E thereby allegedly foreclosed opportunities for competitors to gain access to PGT to sell more competitively priced gas as an alternative to A&S supplies.

In DRA's view, supply competition among Canadian producers would have been enhanced had PG&E responded properly to FERC and Commission initiatives to promote open transport access and had the PGT pipeline been used as a transport link to market spot gas to California. Such competition over time would have caused a decrease in gas prices.

DRA/SMUD argue that PG&E could have taken steps to promote competitive open access over PGT by various alternative options. These options can be summarized in three categories, as outlined below:

1. reducing takes under PG&E's Service Agreement for noncore customers, thereby freeing up space on the interruptible queue for Section 311/7(c) shippers to sell directly to noncore customers;

2. applying for a Section 311 "certificate"[6] to enable it to import gas on its own behalf; or

3. using its affiliate relationship to ensure that PGT accepted its blanket open access certificate under FERC Order 436 sooner, thereby permitting PG&E to convert its sales rights to firm transport rights on PGT.

According to TURN, allowing other Canadian producers equal access to PGT capacity would probably not have resulted in "dramatically lower" Canadian gas costs for California. TURN does not believe a truly free market could have been achieved during the record periods because of the PGT capacity constraint on gas deliveries to California and because of the embedded cost-based pricing for that capacity. TURN still believes, however, that PG&E should have taken steps to secure open access transport rights over PGT for use as bargaining leverage with A&S producers.

6 As correctly pointed out by PG&E (Opening Brief, p. 199, Fn. 123) there is no express provision requiring the issuance of a "certificate" under Section 311. Nonetheless, this technicality does not mean that PG&E could not have used the provisions of Section 311 in the interests of its ratepayers, as explained below.

Thus, to evaluate the feasibility of actions which DRA/SMUD claim PG&E could have pursued to promote open access over PGT, we must first assess PG&E's handling of core election.

3. Open Access Versus Core Election: Was PG&E Prudent in Its Core Election Policies?

a. Background

Under the gas restructuring rules which took effect May 1, 1988, noncore customers could choose either to (1) bypass PG&E and purchase gas directly from third parties (the Utility Electric Generation Department (UEG) did not have this option) and arrange for transport over PGT and PG&E pipeline facilities; (2) purchase from PG&E's noncore portfolio; or (3) participate in core election and purchase from PG&E's core portfolio.

In our gas restructuring rules adopted in D.86-12-010, we defined the "elected core" as "those noncore customers with a similar price security preference as the core. They will share the mix of gas supplies purchased for the core." (22 CPUC2d 491, 530.) A noncore customer could elect into the core by signing a minimum one-year agreement with the LDC to commit to service from the core portfolio. Core election was a means of addressing the dual nature of the LDC as both a monopoly with respect to captive core customers and a competitor with respect to noncore customers.

In its 1987 Gas Purchase Policy (Exh. 1007, pp. 2-62 to 2-85), PG&E stated its commitment to seeking to attract as large a core-elect market as possible. PG&E viewed core election as the best means to protect core customers by enhancing the overall attractiveness of its market and providing more bargaining leverage to extract favorable price terms along with supply security.

PG&E's largest noncore customer and most significant candidate for core election was its own UEG department. During the record periods, the UEG utilized large volumes of gas as a boiler fuel. The UEG load averaged 660 MMcf/d during the record periods.

The UEG was unique among noncore customers in that PG&E was both the supplier (through its LDC function) and the customer (through its UEG function) of gas sales. PG&E adopted core election for 100% of its UEG gas requirements effective May 1, 1988 with the implementation of our restructuring rules. PG&E believed that a UEG core election would encourage suppliers to provide the most favorable terms from a cost, price stability, and supply reliability standpoint (Exh. 1007, p. 2-76). Long-term purchases from A&S were predicated in large measure on serving PG&E's UEG load through the core-elect option.

Once PG&E decided to elect into the core portfolio 100% of its UEG load effective May 1, 1988, several other noncore customers followed suit. Core election resulted in a huge addition to PG&E's core portfolio requirements. Essentially the full capacity of the PGT pipeline was thus taken up with A&S long-term gas sold to PG&E to serve its core portfolio.

PG&E thus contracted with A&S producers on the basis of this large diversified load to negotiate more favorable prices. Since A&S gas was cheaper than other sources, it received priority sequencing. As a result, little PGT pipeline capacity remained for other suppliers.

b. <u>Positions of Parties</u>

PG&E asserts that the Commission used core election as a means of capturing the benefits of competition for captive core customers. PG&E further asserts that its decision to implement core election for its UEG was fully consistent with CPUC directives at the time. The Commission recognized that in adopting core election, a potential conflict existed between the goals of (1) increasing noncore open access and (2) extending the benefits of a competitive market to include core customers. (D.89-04-080, 31 CPUC2d 533, 541.) PG&E notes that our primary goal was protection of core ratepayers in preference to maximizing open access (D.86-12-010; 22 CPUC2d, 491, 518). A large core-elect market gave PG&E a bargaining chip in negotiating a competitive price with A&S producers. The ability of core-elect customers to seek alternative fuel options provided an inducement to A&S producers to keep their prices low enough so as to attract this market. PG&E thus linked its high A&S purchases of long-term contract quantities with its commitment to service the core load, including the UEG through core election.

According to DRA/SMUD, PG&E's full core election of its UEG impeded the advancement of competitive open access for noncore customers. If PG&E had not elected its full UEG load into the core, it would not have required such a large supply of sales gas for the core portfolio. PG&E would thus have been positioned to reduce contract takes from A&S by up to 50%, freeing up significant transport capacity on the PGT pipeline. Section 311/7(c) shippers could then have made sales directly to noncore customers at prices allegedly cheaper than that of A&S gas prices. By purchasing its UEG gas from the higher-priced core portfolio under the core-elect option, DRA/SMUD argue that PG&E denied both its UEG and other noncore customers the opportunities to buy gas directly from producers at prices far below the A&S prices paid.

DRA does not explain how increased noncore access to Canadian supplies would have affected core ratepayers, either positively or negatively. SMUD assumes that core ratepayers would have been able to share in any savings realized, but does not adequately explain how this sharing could have been accomplished.

TURN is critical not of PG&E's decision to exercise the core-elect option for its UEG, but rather of PG&E's failure to exploit the opportunity to use core election as a stronger bargaining chip in price negotiations with A&S producers.

IPAC argues that DRA misconstrued our prior pronouncements to imply opposition to having core suppliers serve the noncore market through core election. IPAC views the Commission orders cited by DRA as considering merely whether to grant utilities flexibility to sell gas in the noncore market <u>in addition to</u> core election. IPAC admits there was a tension between the conflicting goals of core protection and open access. But throughout the record periods, we retained the core-elect program.

PG&E dismisses SMUD's contention that absent core election, the UEG could have purchased cheaper supplies independently, and notes that we did not allow purchases for UEG outside the core or noncore portfolios prior to August 1991. D.86-12-010 denied PG&E's petition for separate procurement for UEG to avoid the UEG's siphoning off lower cost supplies. PG&E asserts not only would the core have suffered under SMUD's proposal, noncore customers would likely not have benefited (PG&E Opening Brief, p. 229).

c. <u>Discussion</u>

Parties' dispute over core election involves disagreements both over the merits of core election, itself, and over PG&E's specific implementation of our core-election policy. PG&E's implementation of core election must be evaluated in terms of its implications for both competitive open access and protection of core customers. We must also consider the consequences of core-election in terms of PG&E's obligation to serve and of other options PG&E might have pursued. Thus, we consider whether PG&E utilized the benefits which core election offered in a manner which compensated for loss of open access opportunities.

Prior to implementation of core election on May 1, 1988, we had stated our commitment to open access as a means to promote competition. For example, we stated in our November 14, 1986 Resolution G-2704:

> "...[W]e alert gas producers to our commitment to provide a level playing field for gas to gas competition. 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,

> to have access to the California market." (p. 8)

Segmenting service of customers into separate core and noncore categories could, however, create problems, as we noted in I.87-03-036:

> "...market segmentation carries the risk that core ratepayers, who cannot directly participate in the competitive gas market, may be isolated from the benefits of competitive market forces." (p. 9)

Accordingly, effective May 1, 1988, we adopted the core-elect option as a means to address this potential conflict. The core-elect option was conceived as a means of capturing the benefits of a more open and competitive gas market for all gas consumers. Core-election offered three potential advantages to captive core customers:

1. Improved load factor of the core portfolio, making it more attractive to suppliers;
2. Inclusion of fuel-switchable load in the core portfolio, placing an upper bound on gas costs;
3. A larger market, enhancing utility bargaining power.

Subsequent to the adoption of core election, debate continued as to whether to eliminate core election in order to free up more capacity to promote competitive open access. Opponents of core election pointed to the constraints it posed in terms of limiting open pipeline access and opportunities for competition outside of the A&S producers dominance.

In D.88-12-099, we concluded that:

> "Eliminating core election at this time would cast doubt on the stability of the structure we have established. This would be precisely the wrong signal to send at a time when we are focusing on improving the attractiveness of the California market for

long-term, secure supply arrangements." (30 CPUC2d 545, 559-560.)

Thus, we decided to continue core election into 1989 to provide stability in the structure we had established.

As PG&E correctly observes, to the extent that goals of open access and low cost reliable core service conflicted, our first priority was to safeguard core customers' interests. We later stated in D.90-04-021: "Of course, we encourage PG&E to make available unneeded capacity for transport...but doing this must be in keeping with PG&E's first priority to operate its gas system for the benefit of PG&E's core customers." (36 CPUC2d 158, 166.)

Yet, while we recognized the conflict between the goals of competitive open transport access for third parties and priority access for core customers, we expected the utility to be all the more aggressive, armed now with the new tool of the core-elect market, in negotiating with suppliers for competitively priced gas. We were cautious in our preliminary reaction to core election's success following PG&E's 1988 price redetermination. In D.88-12-099, we stated that our limited experience through 1988 indicated that core-election had worked as an important element in capturing the benefits of competition for core customers. (PG&E brief, p. 177.) We made it clear, however, that the value of core election depended upon how effectively PG&E used it as a bargaining chip in negotiations with A&S producers because while core election offered benefits, it also foreclosed opportunities for competitive open access. For this trade off to be worthwhile, PG&E should have at least held out for prices under core election which were responsive to competitive alternatives which could have been transported over the PGT pipeline. A&S producers' ability to serve the core-elect market should have been conditioned on their responsiveness to such alternatives.

In its filed comments in R.88-08-018 dated November 10, 1988, TURN explicitly identified its continuing support for core election as a tactical maneuver pending the success of PG&E's April 1, 1989 A&S price redetermination. In the following month, in D.88-12-099, we stated that "we agree with TURN that our reasons for retaining the core-elect option at this time are based on a tactical perspective..." Thus, while we acknowledged its value, our support of core election was predicated on the effectiveness with which PG&E used it to bargain for a competitive price with A&S producers in subsequent price redeterminations.

PG&E claims that it did in fact effectively use core election as a bargaining chip with A&S producers, citing our statement in D.88-12-099: "PG&E's customers enjoy the lowest gas prices in the state. TURN's analysis of current gas supply arrangements demonstrates that, absent core election, the price of Canadian gas to both the core and the noncore markets would be much higher...We agree with TURN that, given the current structure of gas supply relationships, we should not throw away what is now a significant bargaining chip." (30 CPUC2d 545, 560.)

Our observation about the 1988 price redetermination in D.88-12-099 assumed that the large core elect load served to lower the price which PG&E would have otherwise paid for A&S gas. We reached this conclusion, however, based upon then-existing prices as represented by parties in that proceeding. We did not have before us a complete evidentiary record as to the full range of bargaining options available to PG&E during its price redetermination conducted the previous spring.

The bargaining leverage of core election was acknowledged by the Canadian Producers' Group (CPG) in its comments before the Commission concerning the 1988 price negotiations (as cited in TURN's comments in R.88-08-018/I.87-03-036; Exh. 1300, Attach. B, p. 7). Yet, CPG also noted that the dramatic upturn in Southwest prices in the late Spring and summer of 1988 had not been anticipated or factored into the negotiations. Thus, PG&E's use of core election as a bargaining chip cannot be given credit for savings which were not even foreseen during negotiations.

Moreover, we conclude that PG&E did not take full advantage of the bargaining leverage which core election afforded by inducing price competition <u>among</u> Canadian producers, rather than simply <u>between</u> A&S producers and U.S. producers. TURN had observed in its R.88-08-018 comments that there were emerging indications--albeit sketchy at that time--that the price that would result from competition <u>among</u> Canadian suppliers would be well below the A&S price then in effect of $1.81.

Despite the concerns raised by TURN in November 1988 regarding the lack of competition among Canadian suppliers, PG&E offered up its core-elect market in its 1989 and 1990 price redeterminations without requiring A&S producers to factor in competition among Canadian suppliers in developing a contract price. We did not eliminate the core-elect option in the aftermath of PG&E's price negotiations with A&S producers in 1989 and 1990. Nonetheless, by the middle of the 1990 record period, in D.90-07-065, we expressed concern as to whether PG&E was bargaining aggressively to maximize the full competitive benefits of core election. Given the foregone opportunities for open access necessitated by PG&E's large UEG core-elect load, we observed:

> "PG&E's UEG loads dampen competition in ways which are costly to all ratepayers.

> Because PG&E buys gas through its affiliate, A&S, and passes along the costs of the gas to ratepayers, dollar for dollar, PG&E may not have an adequate incentive to bargain hard with producers. Contributing to this is PG&E's exclusive access to PGT, which arises in large part because of the service PG&E provides its UEG." (D.90-07-065.) (37 CPUC2d 87, 109.)

We reminded PG&E in that decision that we would be scrutinizing the reasonableness of its Canadian purchases in a subsequent reasonableness review. We also expressed criticism of PG&E for failing to develop more flexible contract relationships over a period of time in which we had stated our intent to move toward competition in all gas markets. To the extent UEG core election resulted in filling the PGT pipeline with A&S contracted gas, it also reduced the transport capacity otherwise available to Canadian producers outside the A&S pool. As we observed in D.90-07-065: "It appears that Canadian suppliers are not given equal opportunities to negotiate sales agreements and seek access to the California market." (37 CPUC2d 87, 109.)

In D.90-09-089, we further revised our restructuring rules effective August 1, 1991, to replace core election with "core subscription" and restrict UEG procurement from the core portfolio to no more than 65% of its demand.

Our statements concerning the apparent success of core election during the 1988/89 record periods therefore cannot be construed as de facto findings of the reasonableness of PG&E's specific implementation of core election. Clearly, the success of core election depended on how well PG&E used it as a bargaining chip in negotiating with A&S producers. Since our reasonableness reviews of PG&E's actions in negotiating with A&S producers have been deferred until now, we could not and did not render a conclusion on the overall merits of PG&E's management of core election before now. In the absence of a fully developed record, we could not know at the time of our preliminary assessment the extent to which competition among Canadian producers was a factor in any core election strategy.

We acknowledge our pronouncements made before and during the record period, characterizing the core-election program as a useful tool to provide benefits of a competitive market to captive core customers. We do not believe, however, that PG&E took full advantage of the bargaining leverage promised by a large core-elect market to stimulate competition among Alberta producers. To this extent, PG&E's core election implementation was not in ratepayers' best interests. We discuss the reasonableness of PG&E's bargaining tactics with A&S producers in Section VII.

PG&E's primary goal should have been to elicit a more competitive price from the A&S pool using the "carrot" of core election to do so. Had it done so more effectively, then full core election dedicated to the A&S pool would have been appropriate. If the A&S pool had resisted a competitive price agreement, then PG&E could have credibly threatened the alternative of reducing the amount of core-elect load offered to the A&S pool and substituting cheaper Canadian gas.

In summary, we disagree with DRA/SMUD that it would have been prudent for PG&E to decouple its UEG load from the core-elect option as a way to promote competitive open access. It was prudent for PG&E to maximize core election as a means to secure the benefits of competition for captive core customers. The problem was not with the amount of core election, but rather with PG&E's

failure to maximize the bargaining leverage which core election offered in negotiating with the A&S pool. Even assuming maximum core election, PG&E was not obligated to tie up 100% of the PGT pipeline with purchases from the A&S pool if more competitively priced gas was available elsewhere. As discussed in Section V.C.5, PG&E could have exercised transport options which would have promoted intra-Alberta competition for sales transported over the PGT pipeline while still maintaining a high core-elect load. We address in Section VII how PG&E could have used core election more aggressively to achieve more competitive prices.

4. Could Noncore Customers Have Purchased Gas More Cheaply Directly from Canadian Producers Under the Section 311 Shipper Queue?

a. Positions of Parties

DRA/SMUD argue that as an alternative to core election, PG&E's noncore customers could have achieved lower cost gas had they been able to access the PGT pipeline through the Section 311 shipper queue, thereby circumventing the A&S pool. A FERC order was issued at the end of July 1989 authorizing PGT to offer interruptible transportation service under Section 311. PGT implemented this interruptible transportation service on a priority system based upon a shipper queue that had been established by a February 1987 lottery, allocating the scarce PGT capacity. This lottery had initially been held in anticipation of acceptance of a Section 436 certificate. The shipper queue was subsequently used to determine transport access under Section 311. Very little capacity was left for open access by interruptible shippers. During the record periods, interruptible shippers were able to use only 0.7% of the total PGT delivery pipeline capacity using Section 311/7(c) provisions.

DRA made no separate calculation as to how core ratepayers may been impacted had noncore customers pursued this alternative. SMUD, however, did calculate three separate alternative scenarios for allocating alleged overcharges among the UEG, other noncore, and the core, as presented below:

SMUD's RANGE OF OVERCHARGES FOR CANADIAN GAS
$ IN MILLIONS

	Proportional Allocation	Least-Cost Allocation	50% Allocation to UEG
Total UEG	$231.6	$445.9	$347.9
Other Noncore	146.8	223.7	104.8
Total Core	155.7	0	110.6
Total Resale	5.6	0	4.0
Total Overcharge	$539.7	$669.6	$567.2

The low end of SMUD's range assumes PGT capacity is allocated to each major service class in proportion to PG&E's systemwide deliveries (i.e., "proportional allocation"). Thus, core and noncore customers would have been recipients of cost savings in proportion to their gas loads. SMUD assumes that PG&E's UEG department had procured gas independently of the core portfolio directly from Canadian producers or marketers at prices no higher than the average publicly reported price in one-year firm direct purchases. In contrast to DRA's spot price proxy, SMUD argues that the one-year firm price provides a more direct comparison with A&S prices which are redetermined annually. For other noncore customers, SMUD assumes prices could have been achieved equal to Alberta spot prices. For the captive core, SMUD assumes PG&E would have continued to procure reduced volumes under the A&S producer contracts, but at a reduced price based on a 50/50 split between an assumed Alberta market price and U.S. Southwest prices. For the core class, SMUD used the average field price paid by Alberta's largest aggregator pool, Western Gas Marketing Limited (WGML).

As an alternate least cost allocation, SMUD assumes UEG and other noncore customers could have procured Alberta gas at a lower price than could be attained for the core portfolio, and that all UEG gas load would have been procured in Canada. SMUD assumes further savings in electricity to the extent that lower UEG gas prices figure in the calculation of purchased power. Under this scenario, all disallowance savings would accrue to the noncore while core ratepayers would neither gain nor lose. As a mid-range estimate, SMUD assumes 50% allocation of PGT capacity to the UEG. This is SMUD's "preferred" recommendation. Although it computes this range of overcharges, SMUD does not represent them as precise figures for quantifying a disallowance and characterizes its calculations as "symbolic and notional." (Tr. 4869.)

PG&E disputes DRA/SMUD's assumption that reduced core election would have resulted in more PGT pipeline capacity becoming available to noncore customers, resulting in lower prices for the noncore. At best, PG&E asserts that DRA/SMUD's hypothetical procurement alternatives would have benefited noncore at the expense of core customers. If cheaper A&S supplies were diverted from the core to the noncore sector, PG&E contends it would have had to purchase a higher percentage of the more expensive, less reliable Southwest spot gas for its core portfolio at an added cost of $216 million. PG&E further contends that not only would core customers had paid more, but noncore customers would likely not have benefited. Canadian producers were as likely as California buyers to gain control of PGT capacity had PG&E relinquished it. If Canadian shippers had obtained control of PGT capacity, they would have sold gas into California at the prevailing California market price.

PG&E further asserts that the Commission recognized that LDCs had various concerns during the record periods over conversion risks. DRA did not factor these issues into its analysis according to PG&E.

IPAC disputes DRA's view that interruptible shippers would have offered noncore customers lower prices than A&S even had they obtained access to the PGT pipeline. Only two out of the top

13 shippers on the Section 311 queue were end-users. The remainder were either marketers or producers. Thus, the latter would have an incentive to market their gas in California at the highest price obtainable. A small set of interruptible shippers would thereby reap the economic rents associated with PGT pipeline capacity. Thus, according to IPAC, a prospective California industrial customer would essentially have had two choices: either transporting gas on the El Paso system or purchasing from one of the PGT interruptible shippers. Accordingly, if the PGT interruptible shipper priced its gas just slightly below the Southwest price, then it would get the business.

Also, IPAC contends that A&S producers, limited to 50% takes, would have had no incentive to provide PG&E's core portfolio with gas competitive with Southwest gas on an average cost basis. Thus, all ratepayers would have paid more for Canadian gas. Further, A&S would have been unable to take $239 million (Canadian $) of prepaid gas, and would have incurred breach of contract costs due to failure to take contracted A&S producer gas, priced "competitive with the price of major competing energy sources in the market of .... PG&E." (Exh. 1503, Tab 3.)

b. <u>Discussion</u>

We first address the alternative of the noncore purchasing directly from suppliers outside of the noncore portfolio, rejecting PG&E as a gas merchant. Noncore customers can be divided into two groups: UEG and all others. We agree with PG&E that the option of direct purchases of Canadian gas targeted exclusively to the UEG apart from either the core or noncore portfolio was not realistic during the record periods. Our policy as stated in D.86-12-010 was to preclude the utility from targeting its cheapest supply sources to noncore customers in the interests of protection of the core. We specifically rejected a PG&E proposal to procure gas to serve its UEG load as a separate entity.

(22 CPUC2d 491, 504.) Thus, the remaining option was for the UEG to purchase gas through PG&E's noncore portfolio.

For noncore customers other than the UEG department, direct purchase would have been an available option had they not elected core service. For significant PGT pipeline transport capacity to have been available for such noncore customers, PG&E's UEG department would have had to forego core election for at least some portion of its demand. We conclude, however, that even if PGT pipeline capacity had been made available, noncore customers likely would not have been able to procure gas on their own independently of PG&E for a better price than they could obtain from one of PG&E's supply portfolios given the manner in which the Section 311 queue operated. Section 311 shippers would have likely segmented the market to price discriminate, as described by PG&E and IPAC. Any PGT capacity which PG&E made available would have been used under terms of the Section 311 queue which PGT had previously established. The holders of the top 1 Bcf/d of capacity on the PGT Section 311 queue were composed 99% of brokers, marketers, and producers (IPAC, Exh. 1402, Tab 4; p. 38).

Such Section 311 shippers would have logically sought the highest prices they could extract from buyers. To maximize profits, they would have targeted those customers otherwise purchasing production from the U.S. Southwest via the El Paso pipeline. Such prospective noncore buyers would have to take gas from the highest priority holder of capacity of the PGT 311 queue before being able to access cheaper gas from a lower-priority holder of capacity. Such a high-priority holder in the queue would effectively be shielded from competition from lower-priority shippers because of the priority system under which the PGT 311 queue had been established. Thus, direct purchase would not have been a viable option for noncore customers.

Accordingly, we agree with PG&E that the constraint on PGT pipeline capacity coupled with the operation of the

Section 311 queue effectively precluded noncore customers from procuring gas directly from Canadian sellers at prices below those paid to A&S. Yet, we consider this impediment to competitive access to be due to the restrictive manner in which the Section 311 queue allotted scarce capacity on PGT, not due to any intrinsic failure of competition within the underlying Canadian gas market, itself. By its intrinsic design, the Section 311 queue precluded competition by prospective sellers who held a lower priority position in the queue. The design of the Section 311 queue was conceived of by PG&E/PGT originally as a means by which to implement open access under Order 436. The concept of a lottery-generated queue was thought at the time to be the fairest way to implement FERC's first-come/first served policy. After the delay in issuance of its blanket certificate, PGT persuaded FERC to approve use of the queue as a means to determine shippers' access under Section 311. Thus, we shall consider feasible alternative ways in which the PGT pipeline could have been used to promote more competitive prices.

Noncore customers' remaining option, other than core election, would have been to purchase gas through PG&E's noncore portfolio. DRA/SMUD argue that PG&E could have procured more competitively priced Alberta gas for its noncore portfolio if it had reduced the size of its core portfolio by not core electing its UEG Department. With a smaller core-elect customer base, core requirements would have been reduced, freeing up space on the PGT pipeline which could have been used to purchase cheaper Canadian gas for noncore customers.

Assuming all other impediments could be overcome, the success of this option would depend on PG&E's ability as an LDC to acquire superior transport rights on PGT relative to noncore customers acting independently. As discussed in the following section, we conclude that PG&E could in fact have succeeded in gaining requisite transport rights on PGT to position itself to go outside of the A&S pool for some portion of its Canadian supplies. The question then becomes whether the Canadian supplies should have been assigned fully to the core portfolio, fully to the noncore portfolio, or to both on some pro rata basis. A related question is whether PG&E should have significantly reduced the amount of UEG load subject to core election to enhance the UEG's ability to benefit from cheaper noncore portfolio supplies.

PG&E contends that even assuming all other impediments could be overcome, the use of PGT transport for the benefit of noncore customers would be improper since it would disadvantage core customers.

We agree with PG&E that it would likely have disadvantaged core ratepayers had PG&E separately assigned some or all of the lower-priced Canadian gas to the noncore portfolio. This would certainly be true under SMUD's allocation scenarios based upon either "least cost" which assigns zero benefit to the core or "50% allocation to UEG" (SMUD's preferred option) which still assigns a disproportionately low benefit to the core. Such an outcome would be contrary to our stated policy of protecting the core market as a priority goal.

We also agree with PG&E that reducing the size of the UEG core-elect load would likely have increased the core WACOG. A higher core WACOG would result both from changes in the relative portfolio mix of cheap gas versus expensive gas and in any absolute increase in the A&S price resulting from reduced takes of firm A&S gas which would be solely born by captive core ratepayers. We address the expected price effects of a reduced take from the A&S pool in Section VI. As we previously found in D.88-12-099, "...absent core election, the price of Canadian gas to both the core and the noncore markets would be much higher..." (30 CPUC2d 545, 560.) Neither DRA nor SMUD effectively rebutted PG&E's claim that core portfolio costs would increase as a result of replacing Canadian gas with more expensive U.S. Southwest gas. Accordingly, we do not believe that it would have been prudent for PG&E to reduce the amount of its core election and to assign more cheaply priced gas to the noncore portfolio since this would have likely resulted in higher prices for core ratepayers.

SMUD argues that PG&E could have provided selected noncore customers effective access to the PGT pipeline through an auction of rights to participate in buy/sell transactions. (Brief, p. 224.) PG&E states that FERC would not have allowed such an auction for PGT. FERC had rejected a similar buy/sell proposal for El Paso as being inconsistent with FERC's as-billed rate cap and exclusive jurisdiction over interstate pipelines. Likewise, in D.88-12-099, this Commission turned down a request to institute a similar buy/sell program. In that decision, we stated that we did not want an interim solution but a permanent capacity brokering program integrated with capacity brokering regulations ultimately to be approved by FERC. PG&E points to the restructuring which we adopted in D.90-09-089 (after record period procurement decisions had already been made) as the first indication that anything similar to such buy/sell approaches might have been permissible. Thus, we conclude that SMUD's concept of an auction did not constitute a feasible prudent alternative during the record periods.

5. Could PG&E Have Gained Control of PGT Transport Access for Purchase of Canadian Gas Outside of the A&S Pool?

a. Positions of Parties

DRA, SMUD, and TURN argue that PG&E should have exercised its affiliate influence over PGT to accept an Order 436 blanket certificate in February 1988. PG&E could have then converted a portion of its firm sales to firm transport rights, positioning itself to displace up to 50% of A&S gas with alternate gas supplies at lower prices purchased from independent suppliers with transport over PGT. DRA characterizes this as PG&E's "most appropriate" strategy. By converting to firm transport rights, PG&E could have circumvented the interruptible shippers and gained priority transport access to PGT.

As an alternative to transport options under FERC Order 436, DRA argues that PG&E could have had gas shipped on its own behalf over the PGT pipeline under Section 311 of the NGPA. Instead, PG&E never directed PGT to transport gas on PG&E's behalf under Section 311. PG&E continued to hold firm sales rights covering virtually the full capacity over PGT and took no action to make a conversion to free up a portion of its firm sales rights for transportation.

On October 9, 1985, FERC enacted a rule under Order 436 giving interstate pipelines the option of seeking blanket authority to provide new gas transportation services to both their traditional customers and to new customers, including end-users. PGT, however, chose not to elect such blanket authority at the time.

Shortly thereafter, PG&E filed A.85-11-039 seeking to increase its ownership of PGT stock from 50% to 100%. PG&E stated that its 100% ownership of PGT "would assure that PGT's goals and direction would be consistent with PG&E's corporate objectives, would assure greater control for PG&E over PGT's transmission system, and would eliminate potential conflicts between the interests of PG&E and those of PGT's minority stock holders." While we approved PG&E's application in March 1986 by D.86-03-012, we advised PG&E that those who block or thwart gas transport access for California end-users "must bear the burden of proof that such action is in the best interests of all ratepayers" in subsequent annual gas reasonableness reviews.

PGT initially applied for an Order 436 blanket certificate in January 1987, which FERC conditionally granted on August 21, 1987. On January 15, 1988, FERC issued a final order giving PGT 30 days to accept the blanket certificate to provide open transport access under Order 436. PGT did not accept the certificate pending the outcome of its GRC filed April 30, 1987. PGT's Order 436 blanket certificate thus expired by its own terms in February 1988. PGT ultimately accepted a blanket certificate in August 1990, after resolution of its FERC rate proceeding.

PG&E explains the delay in exercise of open access rights under Order 436 as being due to uncertainties surrounding the outcome of the then-pending FERC PGT rate proceeding. A FERC decision on PGT's GRC was delayed by controversy over PGT's cost of service tariff price structure. Certain parties to the FERC proceeding contended that PGT's existing cost-of-service tariff should be replaced by a tariff containing stated rates based upon a "modified fixed-variable" (MFV) method. Under MFV ratemaking, PGT would not be assured of recovering all of its fixed costs.

If PGT had exercised its Order 436 certificate in February 1988, it would have had to file rates that reflect an allocation of costs based upon a projected level of open access transportation. Normally, interstate pipelines accepted open access certificates in conjunction with resolution of their GRC filings according to PG&E. Thus, PG&E contends that it would have unreasonably jeopardized investor earnings and exposed PGT to market risk to have accepted open access before resolving uncertainties in the pending FERC GRC over its cost of service tariff. Roughly $8.5 million of PGT's cost of service was allocated in the rate case to open access interruptible service. Thus, other services would not pick up those costs regardless of volumes actually transported under the interruptible rate schedule. The proposed ratemaking change to the MFV rate schedule alone increased PGT's risk exposure by $868,386 relative to the cost-of-service approach.

FERC permitted parties to the PGT rate proceeding to challenge the continued validity of PGT's cost of service rate structure. PGT subsequently entered into settlement discussions on this issue. FERC did not act upon the final settlement for over 15 months. FERC finally issued an order in January 1990 finding that "PGT's proposal to retain cost of service treatment for its gas costs has been shown to be unjust and unreasonable." (50 FERC ¶ 61,067, at p. 61,127.) FERC ordered PGT to remove the 50% minimum bill from PG&E's tariff. In March 1990, PGT filed to become an open access transporter under Order 436 following issuance of FERC's order on the settlement. PGT was finally granted a 436 blanket certificate in July 1990 which PGT accepted in August 1990.

Thus, PG&E portrays PGT's delay in exercise of its Order 436 blanket certificate as being driven by the delays in FERC's decision in the PGT rate proceeding over which PG&E/PGT had no control. PG&E believes that given the business risk of the pending change in PGT ratemaking procedures, it was prudent to delay exercise of the blanket certificate option. PG&E further notes that FERC gave PGT complete discretion either to accept or reject the open-access certificate, and PGT had full rights to reject the certificate if it so chose. (Pacific Gas Transmission 46 FERC ¶ 61,072 at p. 61,324 (1989).)

PG&E accuses DRA of failing to understand the gamut of federal regulations and the implications of DRA's open access and conversion recommendations. PG&E claims that DRA's witness did not know if open access and conversion were one and the same (Tr. 5915:15-25) and was unaware whether and how PG&E could retain its rights to PGT's capacity after conversion. PG&E argues that DRA is also wrong in believing that open access would have meant that shippers other than those in the existing interruptible queue could have used PGT capacity to move Canadian gas. PG&E states that this would have violated the first-come, first-served policy in FERC Order 436.

PG&E further faults DRA/SMUD for failing to consider the operational risks associated with a customer's conversion of firm sales to firm transportation rights (Tr. 6009:1-8). A customer's conversion of firm sales rights on an interstate pipeline could result in termination of the transportation rights at the expiration of the sales agreement (i.e., pre-granted abandonment). (Exh. 1632, p. 3-8.) PG&E cites our admonition in D.88-12-099 that California utilities should do nothing to imperil their firm capacity rights on interstate pipelines. PG&E cites excerpts from FERC Order 636, issued in 1992 which summarize LDCs' concerns during the record period that led to a reluctance to convert sales rights to transportation. Firm transportation rights were perceived as being inferior to firm sales rights because of reduced operating flexibility, and lack of comparability between firm transportation and firm sales rights according to PG&E. Although DRA had not factored the issues addressed in FERC Order 636 into its analysis, it agreed that the evidence summarized therein should be considered in evaluating the prudence of PG&E's procurement decisions.

IPAC contends that DRA's proposed strategy wouldn't have worked in any case because PG&E would still have lacked pipeline access upstream of PGT. We address this issue in Section V.F.

b. <u>Discussion</u>

(1) <u>Order 436 Blanket Certificate Options</u>

First, we consider whether PG&E was imprudent in failing to convert a portion of its firm sales to firm transport with the earlier exercise of PGT's option for a blanket certificate under Order 436. PG&E's criticisms of DRA's proposal highlight the need for clarification concerning the the relationship between open access and conversion to firm transportation. FERC regulations governing blanket open access certificates (18 CFR Part 284 Subpart G) are addressed separately from conversion of firm sales to firm transportation (18 CFR Part 284 Subpart A). We believe that these two provisions should have been coordinated between PG&E and PGT as

TURN explained in its testimony in PG&E's Annual Cost Allocation Proceeding (ACAP) A.89-08-024 (Exh. 1300, Attachment D). The first step would have been to secure open access status for PGT under Order 436. The second step would have been to immediately convert at least a portion of PG&E's existing firm sales entitlement to firm transportation. By acting immediately, PG&E would have satisfied the first-come, first-served requirement of open access under Order 436 and would still have retained its priority over other shippers for transport access on PGT. As TURN points out, these steps would have given PG&E considerable leverage to bargain for lower gas costs without abrogating its contracts.

TURN's comments in the November 1989 Gas Restructuring En Banc aptly describe how PG&E could have used this strategy:

> "We think PG&E has left too much money on the table...Our solution...is to encourage PG&E to become a 436 open-access pipeline...PG&E has no firm transportation rights today. They have only firm sales rights. Get those rights converted to firm transportation. And then have PG&E open up shop at the Canadian border at Kings Gate [sic] and take bids from Canadian producers. That's the way you're going to get the cheapest gas for California consumers." (Exh. 1086, p. 146.)

We acknowledge that FERC gave PGT complete discretion over whether or not to elect an Order 436 Blanket Certificate. Yet, discretion carries with it responsibility. FERC's granting of such discretion in no way relieves PG&E of the responsibility of answering in this proceeding for the consequences to ratepayers of its choice not to convert it firm sales to firm transport in conjunction with Order 436 open access.

PG&E's primary concern appears to have been to insulate its shareholders from financial risk at the expense of foregone ratepayer benefits of competitive open access. In this respect, we share the concerns expressed by TURN's witness Florio during cross-examination:

> "...[W]hat you are basically looking at is on the one hand protecting a shareholder's interest versus on the other hand protecting ratepayers' interest. And I think when utilities have choices like that, that's where regulators have to be particularly vigilant.
>
> "And I'm concerned that in this instance PG&E's desire to hang on to the cost of service tariff because of the protection it afforded the shareholders may have won out over other options that would have been more beneficial to ratepayers." (Tr. 5145.)

Further evidence of PG&E's underlying motivation to resist conversion of PGT's role from merchant to transporter of gas can be found in an excerpt from an internal review meeting of PG&E's Gas Supply Business Unit in July 1989:

> "Maintaining high pipeline throughput levels will be the GSBU's major challenge to earning full returns as gas supplies tighten over time. In order to ensure throughput, the GSBU should actively continue its merchant role in order to keep its unique gas supply advantages. <u>This should be done despite pressures from regulators, customers, and competitors to retreat from the current role.</u>" (Exh. 1752, p. 1, emphasis added.)

PG&E's desire to protect the profitability of its affiliate, PGT, does not justify PG&E's refusal even to try to induce PGT to become an open access pipeline. The resulting forfeiture of ratepayer savings cannot be excused by PG&E's preference for protecting its affiliate profits and shielding PGT from the risks of a competitive market. PG&E's own estimation of the increased risk exposure resulting from the change in PGT's tariff from cost-of-service to stated rates was less than $1 million. PG&E claims additional risk would have resulted because of PGT's uncertainty in estimating the extent to which conversion rights would be exercised and the resulting reallocation of costs to open access transportation services. (Opening Brief, p. 269.) Yet, since PG&E was the only holder of firm sales rights on the PGT pipeline as well as the parent of PGT, there is no reason why PGT needed to be uncertain over the extent to which conversion rights would be exercised. PG&E, as the only real candidate for conversion, could easily communicate this information to PGT and coordinate the pipeline throughput. In short, PG&E has failed to show that any claimed financial risk to which it might have been exposed through PGT's earlier exercise of the open access option was signficant enough to justify denying ratepayers the savings of millions of dollars in gas costs.

Given PG&E's unwillingness to direct PGT to change its cost-of-service rate design to promote a more competitive environment and its stated aim to maintain PGT's gas merchant function despite regulatory pressures to the contrary, we conclude that PG&E must share responsibility for the chain of delays in PGT's acceptance of an Order 436 certificate. Accordingly, we cannot excuse PG&E's failure to induce PGT to accept the blanket certificate in 1988 on the basis of the FERC rate proceeding delay.

We likewise find unpersuasive PG&E's arguments that concerns over issues raised in FERC Order 636 excused PG&E's failure to convert its firm sales to firm transport rights. PG&E's expressed concerns over pregranted abandonment appear unwarranted. PG&E's stated purpose in acquiring 100% of PGT was to assure PGT's interests were consistent with those of PG&E and its customers. (Exh. 1007, p. 2-55.) Accordingly, through its 100% ownership and control of PGT and as PGT's largest customer, PG&E could effectively avoid any adverse pregranted abandonment or similar problems it might have experienced through an independent pipeline entity.

Moreover, pregranted abandonment would only be an issue where a sales customer's service agreement with a pipeline was shortly due to expire. (Exh. 1632, p. 3.) In the case of the PG&E/PGT Service Agreement, there was no imminent expiration. On the contrary, PG&E's Service Agreement with PGT was part of a contractual chain involving long term Canadian export authorizations through the year 2005. Accordingly, pregranted abandonment was not a realistic obstacle to PG&E's conversion to firm transportation.

(2) <u>Section 311 Shipper Option</u>

Even aside from PGT's acceptance of a blanket certificate under Order 436, we conclude that PG&E could have used the provisions of Section 311 to direct PGT to transport gas on its own behalf as an LDC. PG&E held a unique advantage relative to other prospective Section 311 queue shippers. As IPAC (Schissel) pointed out: "PG&E itself, as a customer, did not face the same risk of interruption as would a normal industrial customer because it is the firm purchaser and capacity holder on PGT and consequently can influence the availability of interruptible space on PGT." (Exh. 1402, Tab 3, p. 18.) In addition to its dominance as a holder of firm sales rights, PG&E owned 100% of the PGT pipeline as an affiliate corporation. In its 1985 application to take 100% control of PGT, PG&E justified its goal in A.85-11-039 as being to "assure that PGT's goals and direction would be consistent with PG&E's corporate objectives, and would assure greater control for PG&E over PGT's transmission system." It would have been consistent with this goal for PG&E to induce PGT to become a Section 311 shipper sooner than July 1989 and to use PGT to transport gas on behalf of PG&E under Section 311. Thus, PG&E, itself, could have simply bypassed the PGT gas merchant function and used PGT merely as a transporter of PG&E's own independently procured gas for a predetermined portion of its Canadian gas purchases.[7]

By contrast to its virtually exclusive use of PGT as a gas merchant selling A&S long-term gas, PG&E took

7 Even if PGT had not become a 311 shipper earlier, PG&E could have converted 15% of its firm sales entitlements to firm transportation rights on August 1, 1989 when PGT actually began open access service under Section 311 (<u>Pacific Gas Transmission Company</u>, 48 FERC ¶ 61,125 (1989), and PG&E could have converted 30% of its firm sales to firm transportation in August 1990 (18 CFR § 284.10(c).)

advantage of Section 311 transportation over the El Paso pipeline to procure U.S. spot gas when El Paso commodity gas became uncompetitive. PG&E was able to accomplish this even without an affiliated connection with El Paso. We believe PG&E could have used its ownership control of PGT to invoke Section 311 service on its own behalf for transport access on PGT. PG&E could have done this even before PGT held its queue lottery in 1987 in anticipation of an Order 436 Certificate. As PG&E, itself, points out, open access was not restricted to Order 436, but could also take place under NGPA Section 311 (Opening Brief, p. 270).

Moreover, as FERC noted in its Order 436: "Under the section 311 regulations, promulgated shortly after enactment of the NGPA, pipelines began increasingly transporting gas for local distribution companies for these utilities to use as part of their own 'system supply'." (FERC Statues and Regulations ¶ 30,665, p. 31,485). Yet, PG&E did not take advantage of this trend.

PG&E could have positioned itself to purchase more competitively priced gas for the core portfolio. Similar to the strategy proposed in connection with PGT's acceptance of an Order 436 certificate, PG&E could have elected to convert a portion of its firm sales rights to firm transport rights. (18 CFR 284.10.) By holding the Section 311 lottery for third-party shippers without seeking first to secure priority firm transport rights on its own behalf, PG&E failed to use a transport option which could have yielded greater bargaining leverage with A&S producers. Thus, while PG&E had priority over third party shippers with respect to its firm <u>sales</u> rights for A&S producer pool purchases, it did not exercise its opportunity for firm <u>transport</u> rights.

We advised PG&E in D.88-12-099 of the importance of LDCs maintaining priority access to pipeline capacity over third parties. In that decision, we urged utilities to explore options to assign access rights to other parties subject to defined terms and conditions, but not to relinquish those rights. Such assigned capacity could be subject to recall to meet "peak-day" core needs. While recognizing the priority for supplies to assure peak-day core demand, we discounted the idea that open access would be foreclosed because the core might need to use all capacity rights on a very few cold days. We envisioned a solution that would secure the core's peak-day needs while still opening transport access at those times when the core is not at peak. As we stated:

> "We clearly do not want the utilities to **relinquish** their firm capacity rights, due to the risk that the rights might be lost permanently. We prefer them to **assign** those rights to other parties for a defined period and under specified terms and conditions. Our real problem is to determine what terms and conditions are necessary to attach to capacity allocation so that core consumers will be adequately protected, yet noncore customers will have access to more reliable transportation through purchasing assigned capacity." (30 CPUC2d 545, 555.)

There is nothing to suggest PG&E would have been precluded in its role as an LDC with firm PGT sales rights and as 100% owner of PGT from exercising priority transport rights under Section 311 for its end-use customers over any third party. Thus, we conclude that had PG&E acted to obtain and exercise Section 311 rights to transport gas over PGT on its own behalf, it could have positioned itself to access alternative Canadian gas supplies.

(3) Section 7(c) Certificate Option

As a further alternative to its transport options under either FERC Order 436 or NGPA Section 311, PG&E could have transported Canadian gas as a Section 7(c) shipper. PG&E could have obtained Section 7(c) interruptible rights from PGT to transport less expensive Canadian gas even before the 1988 record period began. Shippers other than PG&E had been granted Section 7(c) certificates by FERC order prior to the beginning of the 1988 record period. PG&E offers no reason why it could not have applied for and been granted a Section 7(c) certificate before PGT became an open access shipper under either Section 311 or Order 436. Aside from the fact that PG&E could exert influence over PGT through its 100% ownership to obtain such a certificate, PGT was precluded from turning down any such request because it would have been unduly discriminatory. (See Pacific Gas Transmission Co. 41 FERC ¶ 61,019 at p. 61,047 (1987); Pacific Gas Transmission Co. 44 FERC ¶ 61,196 at p. 61,698 (1988).)

Although PG&E's transportation rights under a Section 7(c) certificate would have been interruptible rather than firm, this should not have presented a problem since PG&E, itself, was the only holder of firm rights on the PGT pipeline. Thus, PG&E would have been in a position to control and coordinate the timing and utilization of its interruptible transportation by reducing its own firm sales from PGT. In this manner, PG&E could have transported less expensive Canadian gas under a Section 7(c) certificate.

D. Supply Reliability: Could PG&E Substitute Short-Term for Long-Term A&S Gas Without Jeopardizing Security and Stability of Customer Service?

1. Background

PG&E argues that its takes of full contract volumes from A&S producers during the record periods were required to provide sufficient supply security and price stability for its core portfolio consistent with Commission directives. PG&E asserts that given the supply uncertainties which existed during the record periods, it could not have reasonably assured service reliability at stable prices through Canadian spot gas purchases.

PG&E disputes DRA/SMUD's claims that it could have procured spot gas from other Canadian provinces outside of Alberta.

The dominant source of Canadian natural gas is Alberta which accounts for 85% of Canada's total supplies. Saskatchewan gas supplies were not a practical supply source for California due to lack of physical pipeline connections. Pipeline constraints limited the reliability of British Columbia gas during 1988/89.

DRA/SMUD assert that PG&E was unreasonably excessive in its reliance on contracts with terms of 25 years or more for its Canadian purchases. DRA/SMUD argue that supply reliability was not a constraint on PG&E replacing up to 50% of its A&S purchases with spot gas.

To assess the merits of parties' arguments concerning supply availability and reliability, we must review the nature of the short-term gas market as it had developed at the beginning of the 1988 record period. Following NGPA deregulation, a short-term or spot gas market evolved in the U.S. during the mid-1980s as a significant supply source for LDCs. Prior to the the NGPA, most interstate gas had been sold under dedicated long-term contracts. NGPA deregulation provided the incentive for new production of gas supplies which could be sold on a "spot" or short-term basis.

FERC open access rules such as Order 380 increased LDCs' supply options by freeing them from minimum bill penalties imposed by pipelines as compensation for lost gas sales. The effect of this FERC order was to cause many pipeline companies to be left with excess gas. As gas price ceilings began to rise through the early 1980s, U.S. gas production became overstimulated relative to demand. As production increased, demand for gas went into decline. As a result, a significant market for spot gas developed within the U.S. during the mid 1980s to fill the gap left by pipeline sales gas which had become either too expensive or unavailable.

In contrast to long-term contracted gas sales which obligated the seller to deliver gas at an agreed frequency and price over an extended period, spot gas sales involved shorter periods, frequently for 30 days or less. Whereas a long-term contract implies a legally binding future claim on supplies, there is no such assurance of future access in a spot transaction. Although spot supplies are subject to greater uncertainty, traditionally they also were lower priced than long-term supplies. The lower price compensated for the producer's right to discontinue his spot sales when long-term arrangements became available (Exh. 1503, Exh. C). Spot gas may be transported on either an interruptible or short-term firm basis.

The emergence of a spot gas market in the U.S. Southwest in the mid 1980s offered new opportunities for PG&E to minimize the cost of gas for its customers, but it also posed potential risks and uncertainties with respect to assured deliverability and price stability over time.

In recognition of the growing importance of spot gas as a supply source, PG&E formulated internal written policy guidelines dated August 30, 1985 for the purchase of spot supplies. PG&E noted in the opening text of its guidelines that the spot gas market offered the opportunity "to achieve gas cost savings in the near term, and to encourage the Company's long-term suppliers to offer competitive prices within the context of continued reliable supplies--a result which PG&E sees as clearly preferable to spot purchases." (Exh. 1007, Attachment 2-2.) PG&E's policy further stated that spot gas "should not be purchased before the Company's existing dedicated long-term sources unless clear and significant benefits can be shown."

Parties disagree significantly in characterizing the Canadian spot gas market. DRA/SMUD argue that independent Canadian gas supplies were in abundant surplus and easily sufficient to substitute for up to 50% of A&S contract supplies.

PG&E, IPAC, and CPA argue that the volumes and prices of Canadian spot gas assumed by DRA/SMUD were not available to PG&E during the record periods. PG&E criticizes DRA/SMUD for failing to take into account the significant differences between the U.S. and

Canadian gas markets. For example, Canada did not have an extensive interconnected network of pipeline transport facilities in Canada, nor a well-developed market for exports of spot gas from Canada to the U.S. In addition, there were substantial new requests for Alberta gas from alternative long-term markets in Canada and the U.S. throughout the record periods. PG&E argues that changes in its purchasing practices could have seriously jeopardized its existing and future ability to obtain Canadian gas.

PG&E argues that the competition for Canadian exports was for long-term, not short-term, gas. While U.S. producers were reluctant to sign long-term contracts, Canadian producers were quite willing to do so. PG&E claims that if it had sought spot gas outside the A&S pool, this would have damaged A&S's ability to attract new long-term gas supplies needed for its application to extend its export license. The NEB could have determined that in light of other pending export applications, there were inadequate reserves in Canada to allow such additional exports.

PG&E claims that it had no access to spot gas exported through points other than Kingsgate, B.C., since licensees cannot switch export points without the NEB's approval.

Rather than having the flexibility to reduce its long-term supplies, PG&E contends it had to commit to long-term takes in response to growing demand from other buyer markets for long-term Alberta gas. PG&E/IPAC also dispute DRA/SMUD allegations concerning Canadian gas reserves surplus.

2. <u>Discussion</u>

We must determine (1) to what extent alternative Canadian gas supplies existed and were accessible to PG&E; (2) how reliable they would have been; and (3) whether displacement of A&S volumes would have jeopardized PG&E's customers' long-run supply security and price stability. We must consider competing demands for Canadian supplies which may have been accessible to PG&E.

We must balance criteria of availability and reliability of supplies against customer service obligations, particularly for peak-demand security. In consideration of such customer service concerns, the following portfolio mix problems must be addressed: (1) How much short-term gas should have been purchased in total? (2) How much of such gas should have come from the U.S. southwest versus from Canada? (3) How should total short-term gas have been allocated between the core and noncore portfolios?

For PG&E to purchase the equivalent of up to 50% of its A&S volumes from independent suppliers at prices equal to the spot prices used in DRA's disallowance calculation, certain prerequisites would be required. It is not enough that supplies physically exist. Pipeline facilities must be available to ship the gas from producing fields to PG&E's market. The prices paid by PG&E must be high enough to induce producers not to sell the gas to alternative markets, but low enough to displace other Canadian gas purchased through A&S. Finally, regulatory approvals must be secured from the Canadian government to export the gas from Canada.

In Section V.G, we address the price assumptions which DRA used to value Canadian spot gas. In Section V.F, we address how Canadian governmental actions might have impacted PG&E's access to alternative supplies. Here, we address the supply assumptions concerning the volume of gas which could have been procured on a short-term basis.

As a starting point for our inquiry, we shall assume that any Canadian gas which PG&E could have procured must have come from Alberta. We find persuasive PG&E's arguments that because of pipeline transport constraints, it was effectively limited to the province of Alberta for procurement of Canadian gas supplies.

There are two general means by which PG&E might have bought Alberta short-term gas supplies outside of the A&S producer pool during the record periods: (1) diversion of spot gas sold to other markets during the record periods and (2) procurement of additional supplies from reserves which independent sellers would have been willing to produce (but did not) if offered a sufficiently high netback. There were also two transport alternatives: interruptible or short-term firm.

3. Were Canadian Spot Gas Sales Sufficient to Support Incremental Short-Term Purchases by PG&E?

a. Positions of Parties

Parties disagree over the most meaningful way to measure the size of the Canadian spot gas sales market. PG&E's primary measure is recorded Alberta spot gas sales. PG&E reports recorded sales broken down as "intra-Alberta" (i.e., sales to end-users within Alberta) and "ex-Alberta" (i.e., sales to end-users outside of Alberta). PG&E's sales figures are summarized below for the record periods:

ALBERTA SPOT GAS SALES
(MMcf/day)

			Ex- Alberta	
Year	Total	Intra-Alberta	Firm Transport	Interruptible
1988	585	300	106	179
1989	613	300	245	68
1990	783	300	431	52

Source: Exhibit 1026, Ziff Testimony; Table 5-1

PG&E notes that the entire volume of such spot gas represented only about 5% of the total Canadian gas market and barely exceeded DRA's proposed 500 MMcf/d in total while U.S. spot sales constitutes 65% to 80% of U.S. sales during the record periods (Exh. 1029, pp. 6-19). PG&E asserts such a market was far too small to support the incremental demands assumed by DRA/SMUD.

Moreover, members of the A&S producer pool account for over 80% of all Alberta and British Columbia gas production (Exh. 1008, p. 3-41).

IPAC states that for the entire Canadian market, volumes for interruptible spot gas sales totaled 433 MMcf/d in 1987/88; 340 MMcf/d in 1988/89; and 237 MMcf/d in 1989/90. IPAC notes that volumes were declining over the record periods, attributing the decline to the unreliability of interruptible transportation (Tr. 5590). CPA argues that Alberta spot gas exported outside the province was not reliable in that it was subject to recall if needed to satisfy peak demand of original buyers and it would depend on availability of interruptible transportation. (Tr. 5778-9.)

DRA, by contrast, reports total Canadian spot sales for 1990 of 403,403 MMcf (or 1,105 MMcf/d). A separate Alberta total was not presented. DRA provides no statistics for 1988/89. Yet, IPAC asserts only 237 MMcf/d of U.S. spot imports occurred in 1989/90, as noted above. IPAC contends that DRA erred by including short-term firm gas in its estimates of spot gas in its Table 4.1, and that about one-half of what DRA calls spot gas is in reality sold under firm contracts. (Exh. 1503, p. 5.)

Parties' conflicting figures are further due to use of different data sources. While DRA used U.S. DOE figures, PG&E used figures from Canadian Department of Energy, Mines, and Resources (EM&R), each incorporating different definitions of spot gas. PG&E's spot supply figures represent Alberta gas sold on a 30-day contract basis. The U.S. DOE uses a somewhat broader definition of spot gas.

While PG&E minimizes the extent of spot sales by comparing it to the total Canadian market, DRA magnifies the relative differences in spot sales volumes among the respective U.S. import points based on its volume of 403,403 MMcf of spot gas (or 1,105 MMcf/d) exported from Canada to the U.S. during 1990 (Exh. 1100; Table 4.1). Among individual U.S. export points, the relative mix of short-term versus long-term Canadian supplies varied significantly, as noted by DRA. PG&E took a much smaller relative share of Canadian spot gas as compared with the U.S. import market in general. DRA presents statistics for 1990 on the relative mix of short-term versus long-term gas sales for each of the five major U.S. import points for receipt of Canadian gas, as summarized below:

Import Point	% Spot Gas vs. Total Canadian Imports
Eastport, ID	2.9%
Sumas, WA	86.2%
Morgan, MT	16.5%
Noyes, MN	50.7%
Niagara, NY	43.1%
Average	29.2%

Source: Exh. 1100, p. 4-5.

While only 3% of the gas from PGT's import point at Eastport, Idaho consisted of spot gas, DRA reports that spot gas sales represented 29% of the total Canadian/U.S. import market. Correspondingly, while the mean weighted average combined firm and spot market price for imports at Eastport, Idaho (where only 3% of imports were for spot gas) was $1.75/million British therm unit (MMBtu), the price from other export points ranged from $1.14 to $1.64/MMBtu. The significant disparity in PGT's takes of spot gas relative to other U.S. importers raises questions as to why PGT did not avail itself of more spot gas, according to DRA. Even after adjusting DRA's spot sales figures as advocated by PG&E and IPAC, the ratio of spot sales to long-term sales at Eastport, Idaho (PGT's receipt point) is still significantly smaller than for other U.S. import points. A&S's proportion of sales to licensed volumes was more than twice that of other major Canadian aggregators. DRA finds this disparity to be an additional indication that PG&E relied too heavily on long-term gas in its procurement practices, and thereby paid too much for its gas. DRA concedes, however, that it has not specifically performed an analysis as to the availability, quantity, and price of the alternative gas supplies that were not purchased by PG&E but should have been. (Exh. 1648.)

Aside from alleged measurement errors, PG&E dismisses DRA's comparisons of sales at other U.S. import points as irrelevant to its situation. PG&E claims it lacked access to the Canadian spot gas market which competing U.S. import markets had. PG&E explains the higher mix of Canadian spot gas sales for other U.S markets as resulting from a collapse in the market for gas and an excess of pipeline capacity in various regions. A general economic recession in the U.S. Midwest during the 1980s severely reduced the demand for natural gas, particularly in the industrial sector. This reduced demand forced Canadian shippers and producers to renegotiate more favorable terms with their Midwest customers when market-based pricing was initiated in 1984. Even so, faced with continued low demand and excess pipeline capacity into the Midwest (the two pipeline export points into the Midwest exceeded PGT capacity by more than 40%), long-term Canadian shippers were unable to compete against cheaper Canadian spot gas sales.

At Niagara, PG&E explains the relatively greater imports of spot gas as being due the completion of new pipeline capacity before some of its major expected new customers came online. Thus, for those shippers or buyers who were already obligated to pay high fixed demand charges, spot gas sales filled the void created by the excess capacity.

A similar situation applied to exports at Sumas, Washington. Through the mid-1980s, only about 30% of pipeline capacity had been used, constrained by competition from low-priced alternative fuel sources. When open access transportation became available, short-term gas sales, mainly from British Columbia, were able to compete more effectively with lower fuel oil prices.

Thus, in these markets demand was low relative to transport capacity and the Canadian producers' incentive to increase gas sales led to higher spot sales, according to PG&E. By contrast, on the PGT pipeline, demand was high and transport capacity was constrained. Thus, according to PG&E, there was no reason for Canadian shippers to change their pricing or to sell spot gas.

PG&E believes a more meaningful measure of the spot market was its size relative to the total Canadian market. Total spot sales for Alberta barely exceeded 500 MMcf/d throughout the record periods. If PG&E had sought to compete for any of these limited supplies, it would have had to bid up existing prices to induce suppliers to divert supplies from competing buyers. PG&E (in Ziff's testimony) states that spot gas volumes which did exist within Canada were "sued" to specific markets outside of Alberta. Transfers of these volumes to PG&E would have required provincial and federal approval.

b. Discussion

First we shall address parties' disputes over the actual amount of recorded spot sales. Next, we shall consider the implications of recorded spot sales for the feasibility of PG&E procuring spot gas supplies within Canada. We conclude that the figures provided by PG&E and IPAC provide a more realistic measure of recorded sales from which PG&E would have had access. DRA's higher figure includes gas produced outside of Alberta. As discussed earlier, we conclude that PG&E had no meaningful access to gas outside of Alberta. DRA also includes short-term firm purchases in its reported figures. PG&E would likely have had limited if any access to such gas since existing buyers already had priority firm transport access to such gas.

DRA's figures, however, provide a useful dimension as to the relative proportion of sales among U.S. export points. The dramatic differences in the proportion of spot sales to long-term Canadian sales imported at Eastport, Idaho (i.e., PG&E's import) relative to other import points portray a general pattern which sets PG&E/PGT apart from the norm. It also illustrates the willingness of Alberta producers to export spot gas when sufficient pipeline capacity is available.

If recorded spot gas sales were a complete measure of total non-A&S Canadian supplies potentially available to PG&E during the record periods, we would conclude that there were not sufficient gas supplies outside of the A&S producer pool to accommodate PG&E's demand as high as 500 MMcf/d. Yet, although downplaying the extent of sales volume of Alberta spot gas, even PG&E concedes that Alberta spot supplies became relatively more plentiful during 1990 as compared to 1988/89. PG&E in fact thought they were plentiful enough so as to factor an intra-Alberta price measure into its 1990 price negotiations. Moreover, as discussed in the following section, we need not accept recorded spot sales data as a complete indicator of the Canadian supplies from which PG&E could have procured gas outside of the A&S producer pool.

4. Potential for Short-Term Sales to PG&E From Existing Alberta Reserves

Recorded spot gas sales merely tell us how supplies were allocated given the distribution of demand and pipeline transport constraints during the record period. Recorded sales do not inform us concerning how gas sales would have looked had PG&E announced a demand for some of its gas outside of the A&S pool. We believe a proper assessment of supply availability from which PG&E could have procured gas must consider not only recorded sales, but also gas field reserves from which additional sales could have been made.

Additional gas sales could have been made from uncommitted surplus gas reserves assuming prerequisites had been satisfied. We have discussed contractual issues above. We must further assume that incremental demand existed, transport access was available, and requisite governmental approvals could have been secured. The question is what volume of Canadian reserves were available for short-term sales to PG&E? Also, PG&E would not necessarily have been limited to simply interruptible 30-day spot gas purchases. It could have offered suppliers terms ranging from spot to multi-month to one-year in duration coinciding with the annual A&S pool price redeterminations.

a. **Positions of Parties**

The record shows that Alberta producers outside the A&S pool held at least some uncommitted gas reserves and would have been interested in serving incremental PG&E demand had A&S producer pool supplies not dominated the PGT pipeline. According to DRA, the problem with Canadian gas deliverability was not supply shortfalls, but rather constrained access to the PGT pipeline by independent producers. DRA quotes an industry trade publication published by one of PG&E's own witnesses, Paul Ziff, observing the general Alberta market trend the summer prior to the 1988 record period:

> "Major pipeline buyers and their system suppliers are fighting off disenfranchised (nonsystem) producers eager for market share, even at lower prices. To date, restricted transportation has limited direct sales, maintaining higher prices. The result is higher aggregate revenue for system producers and Alberta, and a frustrating time for would-be direct sellers." (Exh. 1130, Ziff Energy Group Newsletter; Summer 1987.)

PG&E acknowledged that gas-to-gas competition from Canadian suppliers other than A&S was a "competitive force in PG&E's market" in its "Commodity Rate Analysis" for the Spring 1988 A&S Price Redetermination. PG&E further stated therein that it "has received a number of inquiries from Canadian suppliers who would like to sell gas to it directly." (Exh. 1022, p. 7.) Without disclosing the prices or volumes involved in such inquiries, PG&E expressed its preference for A&S supplies due to their "current responsiveness and flexibility."

As another indication of potential Alberta supplies, DRA points to the strong pent-up demand for transportation service on PGT. Requests for all of PGT's capacity were received within 45 minutes after announcement of PGT's filing for a FERC Order 436 open access certificate in 1987. Within the 10-day open season, PGT received 118 requests from potential shippers applying for transportation service. As of June 1988, over 120 potential shippers with a total volume of 12 Bcf were lined up in the PGT queue.

The interest of prospective Alberta producers in serving the PG&E market is further evidenced by the lucrativeness of the netbacks which PG&E sales yielded to the A&S pool. As TURN had observed in its November 1989 testimony in PG&E's ACAP (A.89-08-024) there was the disparity between A&S prices and other market prices available to producers:

> "It is painfully obvious from these figures that there are producers in Alberta who would joyfully sell to PG&E at prices well below the A&S price (and well above their current netbacks), if only their gas could find its way to the market. Once it has firm transportation rights on PGT, PG&E should be able to command similar prices." (Exh. 1300, Attachment D.)

We must further consider the magnitude of available reserves under control of Alberta producers outside of the A&S pool from which sales to PG&E could have been made.

DRA argues that vast reserves of Canadian gas were known to exist during the record periods and that PG&E would have had no problem finding up to 500 MMcf/d of alternative Canadian supplies. DRA cites NEB data showing established gas reserves were 57 trillion cubic feet (Tcf) as of 1988. DRA computes that these reserves would last 29 years at a production rate of 5.4 Bcf/day.

SMUD also presents comparative statistics on the reserve-to-production ratios for Alberta and British Columbia as compared to the south central U.S. region. The Canadian reserve ratio of 18.9 times is sufficient to sustain current production levels for up to 12 years before the ratio would fall to levels as low as that of the chief producing region in the U.S. SMUD also finds the notion of a gas shortage in Canada suspect given PG&E's ability to find sufficient Canadian reserves to fill the PGT expansion project at a netback price 50 cents/dth less than that applicable to the existing PGT capacity. Further, PG&E was able to find additional Canadian reserves to support its export license extension.

PG&E disputes the claims of DRA and SMUD. PG&E argues, for example, that DRA did not establish to what extent the reserves were connected to existing gathering and transmission lines or committed to markets outside California. PG&E criticizes SMUD's analysis of reserves as failing to distinguish between "proved" and "probable" reserves. While U.S. reserve data on "established" reserves excludes "probable" reserves, the Canadian reserves includes the "probable" category. After correcting for such inconsistencies, PG&E computes a Canadian reserve life index (RLI) of 14.5 years, not 18.9 years as SMUD asserts. The 14.5 year RLI is still 1.5 times greater than the U.S. RLI of 9.5 years.

PG&E further contends that even an RLI adjusted to 14.5 years fails to account for Canadian reserves which are not connected to transmission capacity and thus were not producing during the record periods. During 1987, there were about 20 Tcf of non-producing (i.e., "shut-in") reserves in Alberta, versus 40 Tcf producing reserves, according to PG&E.

The major impediment to accessing shut in reserves would have been the lack of connections between the reserve fields and the NOVA pipeline system. Thus, the shut-in reserves could not be transported to PGT. According to PG&E, the lead time for capacity nominations to connect such shut-in gas reserves into NOVA would have been 27 months. Another consideration is what price a producer would require to construct requisite production, processing, and pipeline facilities to bring such shut-in gas to market. PG&E believes it was highly unlikely that many producers would commit to such new investments without a high degree of take certainty at prices high enough to justify such expenditures.

Of the remaining 40 Tcf of producing Alberta reserves, about 20-24 Tcf was contracted on a long-term basis to various aggregators. Most of the remainder was sold on a long-term basis to other brokers or directly to end-use buyers. PG&E estimates that only about 10-12 Tcf would have been capable of production on a short-term basis.

PG&E further points to competing new requests for long-term Alberta gas contracts during the record periods from buyers in the Midwest and Northeast U.S. and also in eastern Canada. Between 1987 and the end of 1992, the throughput capacity on the TransCanada Pipelines, Canada's primary pipeline system, increased from 1,088 Bcf to 1,863 Bcf. PG&E argues that there was substantial competition for Alberta gas reserves well into the summer of 1989, and that any reduction in A&S firm takes during 1988 or 1989 would have jeopardized PG&E customers' future supply of Canadian gas. In such an event, PG&E contends that reserves contracted for its own customers might have gone to the northeast. Also, throughout the record periods, there was a decrease in Canadian gas exploration and development.

b. <u>Discussion</u>

We must render findings on two related issues: (1) the extent of available Alberta gas supplies accessible by PG&E and (2) the reliability of those supplies during peak core demand periods. We address supply availability here and reliability in the following section.

We are persuaded that supplies of gas were available within Alberta and could have been sold to PG&E's market outside of the A&S pool. PG&E acknowledged the potential availability of alternative supplies in its negotiations with the A&S pool. It is evident from the dramatic response of 12 bcf/d to PG&E's lottery for the PGT Section 311 queue, even if we allow for the effects of oversubscription. While a portion of this oversubscription may not be predicated upon established reserves, only 5% of this total was required to supply 50% of A&S volumes. We conclude that transport constraints, not lack of supplies, limited PG&E's access to alternatives to the A&S pool. Had PG&E taken steps to utilize PGT transport to overcome such constraints, as discussed in Section V.C, sufficient Alberta supplies could have been delivered to offset at least a portion of the A&S pool. In addition to the anecdotal evidence, the quantitative evidence supports the conclusion that productive reserves of alternative Alberta supplies existed which could have been accessed by PG&E assuming transport capacity had been made available.

We agree with PG&E and IPAC that the short-term gas market was considered only a residual market and represented a small fraction of total Canadian sales. Yet, nothing stopped PG&E from taking advantage of this residual short-term market as either bargaining leverage or to supplement base purchases of long-term supplies with cheaper spot gas sales. We find that Canadian gas reserves potentially accessible by PG&E were sufficient to provide at least 300 MMcf/d of PG&E demand. It would only require a very small fraction of the abundant proven Canadian reserves to serve as a short-term gas supplement to PG&E's A&S pool.

We agree that the amount of Canadian reserves realistically available to PG&E should exclude "probable" reserves. Accordingly, PG&E's RLI of 14.5 years for Canadian reserves is more realistic than the 18.9 years RLI asserted by SMUD. Likewise, reserves accessible to PG&E should exclude reserves which are nonproducing and which are contracted on a long-term basis to other parties.

Nonetheless, even based upon these considerations, PG&E estimates that between 10-12 Tcf of reserves would have still been capable of production on a short-term basis. Even if we use

PG&E's estimate instead of the 57 Tcf figure offered by DRA, the potential existed for PG&E to procure at least some Alberta gas outside of the A&S pool.

By way of illustration, we can utilize the reserve figure of 11 Tcf (midpoint between PG&E's 10-12 Tcf measure) to compute a conservative availability of short-term Alberta supplies outside of the A&S pool. As previously noted, in 1990, A&S producers accounted for 81% of total Alberta gas production. (Exh. 1008; Figure 3L.) Using the residual of 19% (i.e., 100%-81%=19%), we can reasonably presume that on average, non-A&S producers controlled no more than 19% of short-term Alberta producing reserves, or about 2 Tcf (=19% * 11 Tcf). A supply of 300 MMcf/d would equate to 110 bcf/year, or about 5% of the 2 Tcf reserves noted above. Based upon these calculations, even if we reduce DRA's 57 Tcf reserve figure down to 2 Tcf, this amount would still be sufficient to have produced an average of about 300 MMcf/d for sale to PG&E over the record periods.

Our confidence in the availability of sufficient short-term reserves to serve incremental PG&E demand is further supported by statements contemporaneous with the record periods made by PG&E's own expert witnesses. For example, PG&E witness Lawrence, stated in a November 1988 publication by his consulting group: "PIRA's outlook for Canadian exports can be simply stated. Canada has a vast gas resource and a huge current surplus deliverability." (Exh. 1128.) PG&E's witness Lawrence sought to qualify his assessment of surplus deliverability under redirect examination as referring to "wellhead deliverability; that is capability to produce at the wellhead but not necessarily...to be able to get it to the market" (Tr. 8469-8470). On recross, Lawrence further explained that in the case of PG&E, "surplus deliverability does not have corresponding pipeline capacity to move it to market...It would require perhaps a very considerable investment in pipeline infrastructure, in NOVA, to move that --

some of that gas to market." (Tr. 8471-8475) With this explanation, Lawrence merely confirms our conclusion that it was constrained capacity, not deficiency of Canadian supplies, themselves, that limited PG&E's access to alternative gas sources within Canada. As discussed in Section VI, we conclude that had the A&S pool refused to offer a competitive price for incremental volumes of sales gas above 700 MMcf/d, A&S could have used its existing capacity rights on NOVA to replace such incremental gas from the A&S pool with competitive gas from other producers. Accordingly, PG&E's claim of a 27-month minimum lead time for a shipper outside of the A&S pool to gain access to NOVA capacity is not persuasive. Such a claim assumes erroneously that construction of <u>new</u> NOVA capacity would be required (PG&E Reply Brief, p. 26:14-15). Another PG&E witness, Paul Ziff, had stated in 1988 that "[g]iven the large amount of gas potentially available from the excess contract supply, and available over time from the shut-in gas pool, the industry's excellent replacement rate despite low prices, and pipeline constraints, we conclude that a shortage of gas supply is unlikely to be a significant problem during the near to medium term." (Exh. 1131, p. 2.)

Moreover, even considering competing gas demand in other markets within the U.S. and Canada, we still conclude there would have been enough surplus remaining to serve at least 300 MMcf/d for PG&E's market. An indication of the extent of Canadian surplus supplies relative to competing demand is found in FERC's decision of January 22, 1991 granting a certificate of public convenience and necessity for the PGT Pipeline expansion project. Although FERC focused on future Canadian supply availability beyond the record periods in this proceeding, it also recognized the surplus deliverability situation as of 1988, based upon PGT's own representations of reserve estimates. The FERC decision noted:

> "PGT states that established reserves in the Western Canadian Sedimentary Basin remain at the 70 Tcf level. PGT states further

> that EM&R's latest analysis ('2020 Vision: Canada's Long Term Energy Outlook' Winter 1990) shows Canada's gas production capability at about 4.5 Tcf per year in 1988, thus reflecting a <u>surplus deliverability of about 1 Tcf per year</u>. Additionally, PGT notes that the latest EM&R reference case shows Canadian domestic demand increasing by 1.9% per year and exports growing from the current level of about 1.3 Tcf per year to 2.1 Tcf per year in 2001. <u>PGT also notes that despite this tremendous growth in demand, EM&R projects that the deliverability surplus will persist throughout the period to 2020, averaging almost 1 Tcf per year and never falling below 600 Bcf per year."</u> (54 FERC ¶ 61,035, pp. 61, 157-61,158.) (Emphasis added.)

We find PGT's representations to FERC concerning the significant surplus of Canadian reserves curiously at odds with PG&E's theme in this proceeding of Canadian gas shortages. FERC noted a surplus supply of 1 Tcf per year after considering growth in both domestic and export demand as existing in 1988 and well beyond the 1990 record period.

In conclusion, short-term gas in Alberta was only a small residual element of the total Canadian market. Yet, given the vast magnitude of total Alberta reserves and the subscription for 12 bcf/d (12,000 MMcf/d) by shippers on the PGT pipeline, it would only require a small fraction of the total reserves to supply incremental short-term volumes for PG&E. We conclude that sufficient short-term Alberta gas reserves of gas were potentially deliverable to PG&E during the récord periods through connected pipelines to satisfy at least 300 MMcf/d of incremental demand. We discuss the basis for this 300 MMcf/d supply finding further in Section VI. The question remains as to what extent these surplus reserves would have been sufficiently reliable to permit PG&E to meet its service obligations to provide reliable customer service.

We must also determine what price would have been required to have induced producers to sell the required quantities.

5. Could PG&E Have Absorbed Supply Risk in Canada Given System Constraints?

a. Positions of Parties

A related issue is reliability. Parties are in significant dispute concerning whether Alberta supplies outside of the A&S pool would have been reliable enough to satisfy PG&E service obligations.

PG&E states that supply security was of particular concern during the 1988/89 record periods due to various factors, including the unreliability of spot supplies, higher than expected UEG demand due to a prolonged drought, stricter environmental standards limiting the use of oil, and a perception of the imminent end to the domestic gas bubble. Also, California gas utilities had less operating flexibility than other U.S. utilities with respect to their interstate pipelines because of their high load factors. PG&E's supply/demand balance during the record periods was constrained by its access to interstate pipeline capacity. PG&E received gas through two U.S. pipelines: PGT (1066 MMcf/d) in the north and El Paso (1140 MMcf/d) in the south. Despite the high load factors on these systems, there were no expansions in capacity on any of the systems during the record periods. PG&E asserts that it had very little operating flexibility over these pipelines and that reduction in PGT takes could have compelled more curtailments in the south than those which did occur (p. 6-27). As we noted in D.88-12-099, high gas demand had produced capacity bottlenecks at the receipt points into the El Paso system where the most economical gas could be purchased.

PG&E argues that U.S. spot gas was unreliable during the 1988/89 record periods, and that 100% takes of long-term A&S gas were needed to counterbalance such unreliability to provide peak-day demand capability for core customers. Factors affecting spot gas reliability include the ability of a pipeline to recall substantial volumes with little notice if competing buyers bid higher prices, and the risk of interruptions in delivery if any link from the wellhead to the end-user did not use firm transport capacity. PG&E cites the unreliability of the spot gas market in the U.S. southwest during the 1987/88 winter as a factor influencing its decision to shift its reliance away from spot gas and toward long-term contract gas. PG&E concedes, however, that supply conditions moderated somewhat in the 1990 record period. U.S. spot prices leveled off, and some forecasters began to re-evaluate the imminence of the end to the domestic gas bubble. Overall, given the uncertainties surrounding supply security during the record periods, PG&E asserts that it would have been imprudent for it to have risked customers' service reliability with purchases of Alberta spot gas.

PG&E claims that we found SoCal imprudent for the period April 1, 1988 through March 31, 1989 record period in D.91-09-026 because it failed to adequately consider the unreliability of Southwest spot gas in its supply planning. PG&E finds it inconsistent that it should be judged imprudent for refusing to rely more heavily on spot gas when SoCal was faulted for such action in 1989. PG&E disputes DRA's findings of spot gas reliability from the SoCal report on two grounds: (1) the 90% spot gas reliability factor was an input assumption, not a conclusion, of the study and (2) the study was based on data which post-dated the 1990 record period and would have been unavailable to PG&E during the record periods. In fact, a California Energy Commission (CEC) report dated May 1988 and authored by DRA's own gas policy witness, Natalie Walsh, identified "the inherent unreliability of the spot-market gas" and the need to "balance short-term cost savings against longer-term supply and price security." Southern California Gas Company's 1987-1988 curtailment, CEC, May 1988.

DRA/SMUD believe procurement of independent Canadian supplies would have been feasible without impairing supply reliability because: (1) competitive forces of supply and demand would assure supply reliability even absent long-term contracts; (2) short-term Canadian gas supplies were sufficiently abundant that supply security would not have been a problem; and (3) whatever core reliability problems might otherwise exist could be alleviated by (a) assigning Alberta spot gas purchases to the noncore portfolio or (b) curtailing lower priority customers. No party has offered a specific quantification of the optimal mix of spot versus long-term gas at any given point during the record period.

DRA contends that during the record periods, the reliability of U.S. spot gas "has proven to be very good." (Exh. 1100, p. 3-10.) DRA cites in support of this conclusion its study presented in Southern California Gas Company's (SoCal) A.91-04-038 in which DRA found that 30-day firm and firm/flex spot gas provided reliability of delivery of about 90%. DRA also points to D.86-12-010 as a basis to discount concerns over the need to rely on long-term contracts for supply reliability to the exclusion of spot gas supplies where we noted:

> "...natural gas supply availability is not a major concern in a deregulated, competitive supply market... [B]uyers will be able to secure whatever quantity of gas they desire at a price sufficient to compensate producers for the cost incurred to develop the resource." (22 CPUC2d 491, 527.)

b. **<u>Discussion</u>**

We first identify the criteria by which PG&E would properly evaluate the supply reliability and price stability of prospective sources of alternative procurement. These criteria depend, in turn, on which supply portfolio PG&E chose to receive the alternative Canadian supplies. Thus, we must consider how alternative Canadian supplies may have been assigned between the core and noncore portfolios, particularly if PG&E had declined to core elect some or all of its UEG load. The choices made concerning such portfolio allocations of purchases could have yielded different consequences in balancing supply security versus cost minimization among captive core, core-elect, and noncore customers. Supplies purchased for the core portfolio, for example, would be subject to more stringent reliability requirements than supplies purchased for the noncore portfolio where customers had various options.

As previously stated, the criteria by which we evaluate the supply security effects of independent Alberta purchases depends upon whether such supplies had been purchased for the noncore as opposed to the core portfolio. Since PG&E's premise is that such purchases would have been made solely for the core portfolio, we shall first address supply security on the premise that 100% of independently purchased supplies had been assigned to the core portfolio.

In March 1986 in D.86-03-057, we recognized the potential benefits of diversifying procurement to include spot gas. We further placed the burden on the utility to prove that trading off current cost savings of spot gas for future price moderation is justified and satisfies the general guideline of minimizing acquisition costs over the long-term. In this proceeding, we find that PG&E has failed to show that price or supply security advantages for long-term A&S gas supplies compensate for the lost opportunities for savings offered by alternative supplies.

Based upon our core procurement criteria as stated in D.86-12-010, we directed the utility to procure gas for the core portfolio

> "...which reasonably results in certainty of supply availability to serve core peak requirements, price security greater than can be achieved by relying totally on spot or other market price sensitive supply sources, and which attains these objectives at the lowest possible cost." (22 CPUC 2d, 491, 531.)

Our observation in D.86-12-010 concerning the effects of deregulation on supply availability quoted by DRA should not be construed as a dismissal of the importance of long-term supplies as a component of the core portfolio. As we later elaborated in D.89-04-080: "Although we seek to promote flexibility in procurement practices, we do not intend that utilities should eliminate firm supplies...from core portfolios, because some supply certainty will continue to be necessary, especially during this period of transition." (31 CPUC 2d 536, 537.) We also stated that "under our core procurement guidelines, most of the gas purchased for the core portfolio will be long-term supplies." (D.88-12-099; 30 CPUC 2d 545,555.)

Although we established these generalized criteria, we specifically declined to quantify goals concerning the mix of short-term versus long-term supplies because of lack of sufficient data. (We defined "long-term" as one year or more of fixed gas contract prices (22 CPUC 2d 491,530).) In fact, in our prior rulemaking we had proposed a policy of using short-term, not long-term, supplies to meet core peak needs. We specifically called into question the view that utilities should rely on long-term pipeline supplies to serve most or all core cold year requirements (22 CPUC 2d at p. 529).

We held PG&E responsible for balancing its core portfolio with supplies of varying terms so as to achieve an overall least-cost solution consistent with its service obligations. As we explained in D.85-08-007:

> "We believe that the economic benefits from spot purchases must be carefully balanced against the long-term effect such purchases may have on the cost and reliability of more traditional gas supplies. At the present time, it is difficult to determine where the optimal balance lies because of the uncertainty and volatility in today's gas market.... This is a decision that is the responsibility of management to be made in the context of market conditions

> indicated above, subject to ultimate Commission review." (18 CPUC2d 477, 479-480.) (P. 5.)

We later observed in D.86-12-010 that there remained insufficient empirical data upon which to establish quantitative guidance as to the percentage of long-term gas to hold in the core portfolio. Thus, PG&E has no basis upon which to claim that our policies mandated any particular mix of long-term supplies during the record period beyond the general threshold of a 50% level. We did however, question the premise that it made sense to rely on long-term supplies exclusively to meet cold-year peak demand of the core. Thus, PG&E would not have violated any Commission guideline by purchasing some portion of its Canadian gas on the short- or intermediate-term market.

Our assessment of PG&E's supply security requirements during the record periods must apply these adopted criteria in considering how A&S gas fit into PG&E's overall portfolio supply mix. We have reserved to Phase IIb the comprehensive review of non-Canadian gas costs during the record periods. Nonetheless, our review in this phase must encompass the interaction between purchases from U.S. and Canadian supply basins. We accordingly address first the question of supply availability in the aggregate. Then given the availability of supply, we consider how the supply could have properly been assigned between the core and noncore portfolio.

We recognize that to some extent, PG&E's supply uncertainty would have marginally increased by procurement of short-term Canadian supplies. The question is whether procurement of any additional Canadian supplies would have necessarily jeopardized core customers' service reliability. To answer this question, we must weigh the availability of supplies against the flexibility of PG&E's overall operating system and its ability to react to the dynamics of continually changing supply and demand conditions.

To the extent PG&E had procured alternative Canadian gas for a term less than one year, we must consider how it would have incrementally affected the balance of PG&E's total supply mix, given market conditions confronting PG&E in the Canadian and the U.S. supply regions. We must consider and balance (1) the likelihood that sufficient alternative supplies could have been delivered as needed to satisfy core portfolio requirements; with (2) the degree of flexibility in PG&E's overall supply and operating system to adjust for Canadian supply disruptions without jeopardizing core peak demand needs at reasonable cost. Thus, we review below PG&E's overall gas procurement mix during the record periods and the means by which PG&E adjusted for supply and demand uncertainties.

During 1988, PG&E experienced spot gas deliverability problems as El Paso implemented the unbundling of its transportation costs from production costs in response to FERC restructuring rules. The separation of sales from transport services caused many Southwest producers to shut in supplies because of impasses with customers over delivered gas prices under the new rate restructuring. Thus, PG&E was unable to purchase shut-in supplies at the same time that its electric demand was at a record high. From July 1988 to March 1989, PG&E sought to acquire long-term Southwest supplies, but met with supplier resistance since suppliers hoped for higher prices by waiting. Thus, PG&E relied more heavily on multi-month contracts and spot purchases.

As the 1989 record period began, PG&E was faced with higher-than-expected gas demands due to cold weather. PG&E maintained customer service by increasing storage withdrawals and fuel oil burns at its electric power plants. PG&E continued to experience unusually high power plant demands due to drought-related low hydroelectric availability and nuclear plant outages.

Beginning in August 1989, PG&E began receiving deliveries under new multi-month Southwest contracts, totaling 52 MMcf/d at the California border which were intended to increase system reliability for the 1989-90 winter season. As a result, PG&E's Southwest supply deliveries were reliable during December. PG&E also declared a capacity curtailment in December and switched some of its power plants to fuel oil.

In the beginning of 1990, continued cold weather initially kept gas demand high requiring curtailments at PG&E's power plants and burning of fuel oil in January 1990. As early as February 1990, however, Southwest spot prices moderated and were down to 1988 levels by March. Supply availability improved due to various factors, including greater exploration and development and the previously unexpected emergence of coal seam gas supplies. Also, within Canada, a significant increase of short-term gas exports outside of Alberta developed as a result of Canadian pipeline expansions on NOVA and TransCanada which were completed in advance of downsteam connecting systems. Since Canadian producers had developed reserves in anticipation of the completion of the pipeline expansions and were incurring demand charges whether or not they had a market for their gas, a market developed for these excess Alberta supplies at "distress gas" prices (PG&E Exhibit 1008, p. 3:43:20-25).

Based upon our review of PG&E's record period operations, we conclude that PG&E was not dependent on 100% of A&S pool gas to satisfy a reasonable level of core supply reliability. The issue of supply reliability is not a simple either/or proposition, but is rather a matter of degree based upon a continuum of risk over a range of possible outcomes. Moreover, our criterion of supply security as articulated in D.86-12-010 was to be attained "at the lowest possible cost." Accordingly, it would be imprudent for the utility to pay a premium for surplus long-term supplies which were not essential for core supply security.

PG&E's claim that it needed 100% of A&S long-term contract gas to provide supply security is largely subjective. PG&E offered no quantitative assessment of the loss-of-load probability for core peak-demand periods assuming changes in the mix of long- versus short-term gas in the core portfolio. PG&E's chief gas policy witness Bellenger described PG&E's supply risk assessment as "...more of a qualitative kind of analysis in the broad sense of the word. I don't recall any specific quantitative analysis during the record period, but clearly there was empirical evidence out there in our own experience with respect to certain suppliers that indicated there were issues around reliability." (Tr. 7381.)

The fact that there were "issues around reliability" does not tell us, however, what the specific consequences would have been to PG&E's customers had additional short-term gas been taken. The "issues around reliability" referenced by Bellenger relate to certain deliverability problems experienced in the U.S. southwest during 1988/89 described above. We acknowledge that U.S. spot gas deliveries were uncertain during certain periods of 1988/89 when PG&E's gas demand was unusually high, particularly for its electric department. PG&E's anecdotal accounts of supply uncertainty do not convince us, however, that core service would have been impaired had PG&E procured short-term Alberta supplies for some portion of its Canadian gas supplies.

PG&E's experiences with U.S. Southwest supply uncertainty can also be viewed as evidence of the flexibility and resilience with which PG&E's overall gas supply system can operate while tolerating a certain measure of localized risk. For example, in May 1988, PG&E successfully counteracted higher-than-forecast demands and supply problems by drawing down additional storage inventory, supplemented with Southwest spot purchases, albeit at a higher price. Likewise, in July - September of 1988, faced with higher power plant demands and supply shortfalls, PG&E was able to maintain reliable service by switching to fuel oil as a boiler fuel and curtailing more expensive gas for delivery to its power plants. Likewise, PG&E voluntarily cut back to zero its purchases of long-term El Paso commodity gas and purchased cheaper spot gas instead.

We believe that PG&E's purchase policy overemphasized the criterion of supply security as a basis for essentially 100% takes from the A&S pool while failing to give adequate weight to the goal of least cost procurement. The testimony of PG&E's chief policy witness Bellenger illustrates PG&E's priorities. In cross-examination, when asked whether PG&E considered other Canadian suppliers besides A&S, Bellenger answered:

> "...In order to have reliable gas supplies out of Canada based on the mechanisms that we have already discussed here about reserves, obtaining export licenses for the long term, you just -- <u>it's not based on price</u>. It's based on the ability to contract for reserves and then putting in place a price which is responsive to the market. That is exactly the kind of arrangement that PG&E had already in place with Alberta and Southern. Why--why would--why would we want to go up and futz around with it?" (Emphasis added.) (Tr. 7572-7573.)

This statement indicates that PG&E did not seriously try to seek alternatives to the A&S pool because it was quite comfortable with the A&S pooling arrangement. PG&E's criterion for making this assessment was supply reliability. Price was apparently perceived by PG&E as a byproduct of a market controlled by the A&S pool who could hold the threat of supply security over PG&E's head.

The lack of perfect reliability of individual short-term supplies did not justify completely excluding any such gas from PG&E's Canadian gas purchases, given the potential for cost savings. The point of a supply portfolio is to manage risk by diversifying supplies from many sources and with varying maturities and terms. The risk of any single supply source is less important than the overall risk of the supply portfolio. Moreover, the need for long-term supply security did not stop PG&E from considering it prudent to save ratepayers money by substituting long-term El Paso gas with cheaper Southwest spot gas. So the question is not whether reliance on <u>any</u> spot gas purchases during 1988-90 were prudent, but rather <u>how much</u> spot gas should have been taken and from what supply region. PG&E has not justified from a supply reliability standpoint why the mix which happens to result from full takes of A&S long-term gas was the right one.

As we pointed out in D.86-12-010, "relying on [long-term] pipeline system supplies for peaking purposes is not a costless strategy." (22 CPUC2d 491, 529.) Prudent management requires a careful balancing of the cost-saving flexibility of short-term gas with the risk-reducing stability of long-term gas.

PG&E's flexibility to increase its overall mix of short-term gas can be better assessed by actually looking at its recorded mix of long-term versus short-term purchases over the record periods. IPAC claims that PG&E's total recorded mix of spot gas for 1990 was 37% of total system purchases as compared with an average of 38% for major LDCs (Exh. 1503, p. 5, 6). We find that in making this calculation, IPAC treats as spot gas certain U.S. Southwest supplies which were actually multi-month in nature and more appropriately counted as long-term gas. PG&E assigned these multi-month supplies to its core portfolio as long-term gas to maintain supply reliability (Exh. 1002, p. 4-18/19). PG&E's treatment of these multi-month supplies as long term gas was consistent with our portfolio accounting rules adopted in D.86-12-010 where we defined "short-term gas" as being priced on a monthly basis and "purchased pursuant to contracts which do not include any expenses or charges for failure to purchase gas beyond a one-month period." We defined "long term" as anything exceeding one month for purposes of accounting for supplies to be assigned to supply portfolios. (22 CPUC2d 491-558). By assigning these multi-month Southwest supplies as long-term gas, we find that PG&E's actual percentage of true short-term gas averaged only between 15%-20% of total purchases throughout the record periods. PG&E's mix of gas purchases between short-term and long-term sources on a total-company basis are summarized below for each record period:

Summary of PG&E System Gas Mix Purchases 1988-90

Supply Source:	1988	1989	1990
By Contract Term:	**(In %)**		
Long-Term	80%	86%	83%
Short-Term	20%	14%	17%
By Supply Region:	**(in MDths)**		
Long-Term Sources:			
PGT	365,012	380,789	380,072
Calif.	115,133	87,293	77,009
U.S. Southwest*	116,772	189,346	156,251
Total Long-Term	597,917	657,428	613,332
Short-Term			
U.S. Southwest**	141,404	109,665	124,831
Total Purchases	739,321	767,093	738,163

*Includes El Paso Commodity and Southwest Multi-term Gas
**Includes 30-day Multi-term and Spot Gas

Source: Exhibits 1009; 1013

Given a long-term gas mix averaging over 80% as shown above, PG&E had at least some flexibility to increase its percentage mix of short-term supplies while still maintaining sufficient overall system reliability. These supplies are shown on a total system basis. If we limited our measure only to core portfolio volumes, the percentage of long-term gas would be even higher. We reaffirm our previously stated policy that the majority of PG&E's supplies for core procurement should come from long-term sources. We likewise believe it was reasonable for the majority of Canadian purchases to come from the A&S pool of long-term supplies. Yet, we find no basis in these numbers for PG&E's complete disregard of any short-term Alberta gas opportunities at lower prices simply on the basis of supply security claims.

On the other hand, PG&E was not free simply to disregard the need for adequate long- term supplies to assure that core peak demand could be satisfied. We agree that it was reasonable for PG&E to take a sufficient mix of long- term gas supplies to satisfy this criterion. We recognize that there was an element of uncertainty in planning to meet peak core demand due to factors such as extreme weather conditions, high UEG demand under prolonged California drought conditions, and capacity bottlenecks on the El Paso system. The generally high demands for gas during the record periods reduced PG&E's operating flexibility in scheduling gas deliveries.

On balance, neither full takes of long- term A&S gas at recorded prices nor 50% minimum A&S takes would have provided for core reliability at least cost during the record periods. Each of these extreme take levels is predicated upon contractual--not reliability--requirements. At 50% minimum takes, there was undue risk that core peak demand reliability might be threatened. At full takes, there was undue disregard for the lost savings through procurement of spot gas. A reasonable approach would have been to procure a mix of Canadian supplies somewhere between these extremes incorporating both of the reliability of long-term gas and the price savings of short term gas. We cannot pinpoint precisely where to draw the line between long-term and short-term supplies. Moreover, the complexities of PG&E's gas system calls for constantly changing short-term versus long-term gas mixes on both a daily and a seasonal basis.

Based upon our informed judgment, however, we can determine an average procurement mix within a range of reasonable outcomes. We conclude that average takes of about 700 MMcf/d from the A&S pool would have reasonably balanced the goals of assured core demand reliability and least-cost procurement. At this level, the remaining capacity on the PGT pipeline would have permitted PG&E to purchase about 300 MMcf/d in the short-term Canadian gas market.

If PG&E had substituted short-term Alberta supplies for up to 300 MMcf/d, PG&E's overall percentage of long-term supplies would still have exceeded the 50% general guideline we established in D.86-12-010. We are not persuaded that PG&E would have been unable to provide reliable service assuming such a purchase strategy. We show the revised mix of gas supplies below, assuming short-term supplies are increased and long-term supplies are decreased by 300 MMcf/d:

Effects on Long-Term Gas Percentage
By Increasing Short-Term Mix 300 MMcf/d
(MMcf)

Line No.		1988	1989	1990
1	Short-Term Gas (Increased 300 MMcf/d) 1/	250,904	219,165	234,331
2	Long-Term Gas (Reduced by 300 MMcf/d) 1/	488,417	547,928	503,832
3	Total Gas Purchases	739,321	767,093	738,163
4	Adjusted Short-Term Gas as % of Total Purchases (Line 1 ÷ Line 3)	34%	29%	32%

1/ Annual Volume Adjustment = 300 MMcf/d * 365 days = 109,500 MMcf

In its procurement of U.S. Southwest gas, PG&E had contracted for multi-month gas as a means to enhance supply availability during peak core demand periods while avoiding reliance on overpriced El Paso commodity gas. Likewise, within

Alberta, PG&E may have sought multi-month and one-year firm direct gas supplies as a supplemental means of mitigating supply uncertainty. PG&E curtailed gas deliveries and switched to fuel oil at its power plants during certain months during the record periods as a preferred alternative to taking long-term supplies from El Paso. This same practice could have been applied, if needed, to address delivery uncertainty of alternative Alberta supplies. PG&E could also have attempted to time its purchases of alternative Alberta supplies to coincide with periods of greater seasonal availability.

Contrary to PG&E's contention, we find nothing inconsistent between our findings here and our findings in D.91-09-026 that SoCal was imprudent in dealing with supply uncertainty. The focus of our criticism against SoCal related to its need to keep a greater level of gas storage in the face of supply uncertainties. We did not conclude SoCal should have contracted for more long-term gas to solve its problems. In fact, we found that SoCal should have purchased more spot gas in the fall of 1988 as a means of maintaining reasonable storage levels throughout the winter of 1988. (See Findings of Fact 26 and 27.) (D.91-09-026; p. 13.)

6. Should PG&E Have Reduced the Size of the Core Portfolio?

Our discussion so far has been predicated on the assumption that 100% of independent Alberta supplies would have been procured for the core portfolio. Yet, DRA and SMUD claim another tool PG&E could have theoretically used was reduction of the size of its core portfolio to mitigate any operating risks associated with short-term Alberta gas. Since a significant share of the core portfolio was comprised of UEG core-elect load, PG&E could have reduced the size of the core portfolio by assigning only a portion of the UEG to core election with the balance remaining as noncore load. In this way, the short-term gas could have been assigned partly to the core and partly to the noncore such that the operational risk of 100% assignment to the core alone would have been mitigated. As discussed in Section V.C.3, we do not believe it was in the best overall interests of core customers for core election to be reduced. Moreover, we do not believe a reduced level of core election was necessary for PG&E to maintain core supply security.

7. Did PG&E Have a Different Degree of Procurement Obligation for the Core Elect Relative to the Captive Core?

a. Positions of Parties

An assumption underlying PG&E's argument of supply security is that it was required to provide equal reliability to core elect and captive core customers. Given the large amount of core election during the record period, such an assumption increases significantly the amount of gas subject to exactly equal reliability criteria. DRA and SMUD do not believe, however, that PG&E had a procurement obligation for its core elect customers as restrictive as for the "captive" core. UEG and other core-elect customers' tariffs permit a lower delivery priority under the Commission's gas curtailment rules. Accordingly, DRA/SMUD believe that core election justified procurement under less stringent criteria of service reliability than for the captive core. On this basis, DRA/SMUD dismiss PG&E's argument that A&S long-term supplies were required at 100% volumes to serve the full core portfolio equally, including core elect. Thus, even if one were to assume spot supplies were less reliable, PG&E could have prudently taken more risk to serve core elect.

PG&E states that there was no distinction in procurement obligation either stated or implied for any customer receiving service under the core portfolio, either core or core elect. Under core election, both core and core-elect would have access to the same gas at the same average portfolio price. Thus, PG&E contends that its mandated obligation was to procure gas for the entire core market portfolio, including core elect, with the same degree of supply reliability and price stability. To support this view, PG&E quotes our mandate from D.86-12-009.

> "Under our new industry structure, the utilities must provide the following services: transmission service for all market segments, and procurement service for the core and core-elect customers." (22 CPUC2d 441, 488.)

PG&E faults DRA's observation concerning differences in curtailment priorities among various customer classes as being relevant only to determining actual gas sendout, not to procurement planning. The underlying concept of a single core portfolio was to link, not to separate, the procurement for two otherwise distinct groups, the captive core and the core elect, according to PG&E.

PG&E further points to the core elect curtailment argument as an example of the inconsistency of DRA's underlying case. PG&E claims that DRA's original position was that supply reliability was not a problem in serving the core portfolio. Only later in the face of PG&E's rebuttal to DRA, DRA formulated a new theory, side-stepping the supply reliability argument altogether by simply claiming that core elect customers were not entitled to supply reliability as were other core customers.

b. <u>Discussion</u>

We agree that under portfolio accounting rules, PG&E was not to target a different mix of supplies to captive core as opposed to elected core customers for purposes of procurement. Curtailment priority distinctions between captive versus elected core customers related to intrastate transmission reliability, not to procurement of gas. We made this distinction clear in D.86-12-010 where we stated that firmness of transmission service:

> "applies only to transmission within California, not to out-of-state pipelines...A capacity related curtailment would be due only to transmission constraints intrastate. We do not want the utilities or this Commission to

> determine whether the inability of suppliers to deliver sufficient gas to the California border is due to transmission or supply problems." (22 CPUC2d 491, 509).

Thus while a different mix of supplies should not be targeted for the core-elect, that doesn't mean that core elect customers did not diversify the overall load to be served. This load diversity contributed by core elect customers should have been considered in procuring a balanced mix of supply sources for all core customers. During our consideration of procurement rules in R.86-06-006, SoCal had stated that the portfolio needed by core-elect customers was less reliable and more price-volatile than that desired by core customers. Because of this, SoCal stated that it was open to the idea of a separate portfolio for the core-elect market. In arguing for a common supply portfolio for both core and core elect, PG&E did not deny that core elect customers had different preferences. Rather, PG&E contended that "a diverse core supply portfolio with sufficient flexibility will serve to protect against core rate increases caused by noncore customers' choosing elected core procurement services." (22 CPUC2d, 491, 517.)

Thus, the synergistic benefits of core election enhanced the opportunity of PG&E to diversify the core portfolio with flexible short term supplies as well as a base amount of long-term gas. This diversified mix would be shared equally between captive and elected core customers. In any event, as previously discussed, PG&E could have provided procurement reliability to core customers while seeking short term Canadian gas for PGT pipeline requirements in excess of 700 MMcf/d.

8. Did the Price Stability Features of A&S Gas Justify 100% Takes to the <u>Exclusion of other Alberta Alternatives</u>?

a. <u>Background</u>

Another supply procurement guideline we established for the core portfolio related to price stability. In D.86-12-010, we assumed that the core market is price risk averse and places a value on price stability achievable through long-term contract. (22 CPUC 2d at 527) But, again, we noted the lack of empirical evidence as to whether or how much risk aversion was really warranted or how much of a premium over current market price was reasonable in exchange for price stability. (22 CPUC 2d at 528) We further noted that: "Our definition today of where short-term ends and long-term begins is necessarily artificial given that we expect the market to develop standard contractual forms...on a fixed price basis for a term greater than one month." (22 CPUC2d at 530.) With that understanding, we then defined a "long-term" contract as one offering a fixed price for one year or more. Subsequently, in D.89-04-080, we relegated the goal of price stability to a secondary priority behind supply security and cost minimization.

Prior to D.86-12-010, A&S producer gas had been subject to semi-annual price redeterminations. In order to qualify as a base load resource for the core portfolio, A&S producers agreed to accept annual price redeterminations to conform to the Commission definition of a "long-term" contract.

b. <u>Positions of Parties</u>

PG&E portrays the price stability offered by A&S gas of a minimum of one year as another reason justifying full takes of A&S gas. According to PG&E, the price-stable A&S gas insulated ratepayers against the risks of price increases in the U.S. Southwest basins.

In addition to annual price stability for base volumes, PG&E further points to the downward pricing flexibility of the A&S "Tier II" rate as a competitive feature of A&S gas prices. The A&S Tier II rate mechanism, implemented in 1985 as an amendment to the A&S/PGT Gas Sale Contract, allowed a portion of the long-term A&S supply to be priced at a level matching lower cost spot supplies bid to PG&E by others. As described in PG&E's 1987 purchasing policy, the Tier II mechanism worked as follows: PG&E committed to take up to 1200 MMcf/d of long-term A&S/PGT contract gas, regardless of availability of cheaper sources. Beyond the 1200 MMcf/d threshold, A&S supplies would still be taken if alternative supplies were no more than 20 cents/MMBtu below the A&S Tier I price (i.e., the negotiated price for long-term volumes). If the alternative supplies fell in price below the 20 cents/MMBtu window, A&S would "flex down" its commodity price under the Tier II mechanism to meet the competing price allowing A&S to retain sales without having to bid against competitors. The 20 cents window was reduced to 10 cents when the gas purchase policy was revised in May 1990 (Exh. 1007, pp. 2-210 to 2-224). In August and November 1986, we approved a Tier III rate targeted to certain customers who would otherwise have by-passed PG&E's system.

DRA argues that PG&E's purported price security benefits of A&S gas were illusory. DRA notes that the annual A&S price redeterminations were based on the price of Southwest alternatives, so that if Southwest prices increase, then A&S prices will move up as well. (Tr. 1908.) (Tr. 7112.)

DRA contends that the PG&E/PGT Tier II/Tier III rate design was unfairly discriminatory and anticompetitive with respect to U.S. Southwest gas. DRA argues that by permitting A&S to retain control over sales volumes under the Tier II mechanism, PG&E discouraged competition. Through its netback pricing arrangements and PG&E's rate design structure, PG&E preferentially sequenced A&S over Southwest supplies, and paid higher prices which would have been lower under competitive bidding according to DRA.

PG&E discounts DRA's criticisms of the Tier II mechanism. First, minimal amounts of gas volumes priced under the Tier II and Tier III mechanisms flowed during the record periods. Tier II volumes accounted for 0.2% of PGT sales while Tier III volumes were even lower.

Second, such sales were approved by the Commission. Likewise, in reasonableness reviews prior to this one, DRA found PG&E's use of the Tier II mechanism to be appropriate. Third, PG&E contends that customers benefited from the Tier II/III pricing. PG&E points to ratepayers benefits of the "downward-only pricing" flexibility of Tier II in the form of costs $11 million lower than would otherwise have occurred.

Discussion

We expressed skepticism in D.86-03-057 as to the relative long-term benefits to ratepayers of certain contracts which may purport to offer price security:

> "If supplies [under long-term contracts] merely lag price changes for spot supplies by a few months, such contracts with producers offer utility customers price stability only relative to the volatile changes found in the spot market. We therefore question the degree to which utilities should value those supplies by attaching a premium to these purchases relative to spot..." (20 CPUC 2d 628, 635.)

We clearly placed on utilities the burden to prove the prudence of trading off foregone opportunities to purchase cheaper short-term gas against the price security of long-term contracts, further stating:

> "We expect utilities to carefully document the ratepayer benefits associated with pipeline purchases in terms of future dollars saved and compare this with the costs incurred today as price premiums over spot prices. Until we see substantial evidence that the pipelines' gas supply contracts will actually guarantee future price moderation for core ratepayers when spot prices inevitably turn upward, we will remain skeptical of the reasonableness of utility reliance on higher-priced pipeline supplies for service to the core market." (20 CPUC2d; 635.)

The A&S contracts provided for some measure of price stability compared with U.S. spot price fluctuations. To the extent we find that PG&E had at least some opportunity to procure short-term Canadian supplies at lower prices, the A&S contracts were of even less value in offering a tradeoff of long-term cost savings.

Even though its one-year price offered a measure of stability compared with spot gas, A&S gas provided only limited protection against the risks of price changes over time. The A&S contract price was renegotiated by reference to movements in the price of U.S. Southwest gas. Thus, ratepayers were still placed at risk with A&S gas for future uncertainties over price increases in the U.S. Southwest gas market.

Any price stability benefits which may have been offered under the annual A&S price redetermination must be weighed against the potential lost opportunity to capture downward trends in spot prices by being locked into long-term commitments. As to the merits of the Tier II price, we conclude that it represented an improvement over merely a fixed price with no downward flexibility. The limitation in the Tier II price, however, was that it was only applicable to a rather small, nominal volume of sales, so that any purported benefits were likewise dwarfed. Moreover, for the limited volumes to which the Tier II rate did apply, it did not permit PG&E to take advantage of a fully competitive market. A&S producers did not have to bid competitively against Southwest producers, let alone Alberta competitors for Tier II sales. Rather than simply allowing A&S to match the Southwest price after the fact, a competitive bidding process over time would have imposed greater downward competitive pressure on all gas prices with PG&E's market. It would have prompted Canadian spot gas suppliers to bid against Southwest supplies and with A&S producers.

Using Tier II and III pricing provisions, only <u>portions</u> of the A&S supply could be priced to compete with PG&E's other supply options. PG&E is thereby allowed to set the price paid to the affiliate <u>after</u> the gas actually flows. This preferential pricing arrangement shielded A&S producers from the need to bid competitively against Southwest spot sellers. In approving PG&E's Tier III Canadian gas sales contract with other utilities, we stated our anticipation that open transport access would promote greater competition from Canadian producers and lower prices. (Resolutions G-2703/4.)

Under PG&E's 1985 Spot Gas Policy, all reliable competitively priced, long-term supplies which met U.S. Southwest spot gas price competition would be retained and would not displace spot gas. PG&E argued that gas supplies best meeting the core portfolio criteria should be retained. However, by just meeting the spot price, PG&E gained a price advantage over its competitors since the price would come down only if and when spot prices came down.

We stated in D.89-04-080 that in the long-run, an overemphasis on price stability may undermine our goal to promote lower prices. (31 CPUC2d 533, 536.) The overemphasis of policies promoting price stability may lead to higher core costs because such policies could send wrong price signals to large users and encourage utilities to enter into fixed price contracts which would ultimately be expensive. (<u>Id</u>. 533, p. 536.)

The comparison of A&S and Southwest spot gas which PG&E offers as a demonstration of ratepayer savings does not address the long-term trade-offs discussed above and also ignores the potential for savings from alternatives within Canada.

c. **<u>Conclusion</u>**

In conclusion, the supply security or price stability benefits offered by A&S gas do not justify purchase of 100% of PG&E's Canadian supplies through long-term contracts considering the lost opportunities foregone to purchase cheaper gas. PG&E has not met its burden of proof that the price stability features offered through the A&S producer pool justify the loss of cost savings which could have been achieved through the short-term gas market. In D.86-06-006, we reached a similar conclusion with respect to PG&E's failure to justify payment of the large premium of long term over spot gas on the El Paso pipeline. Our comments in that decision are applicable here:

> "We are very disturbed by the increasing premium above spot that core customers are paying for long term dedicated supplies...PG&E has not explained or sustained its burden of proof as to why it is reasonable to pay such large premiums for sales gas. If PG&E desire competitively priced gas for its core customers, it must go out and negotiate further with the pipelines or even directly with producers...It is not our intent to be shortsighted with regard to gas procurement policy. It is critical, however, that we have a precise understanding of the long run benefits being received for the premium we are currently paying for pipeline supplies. (21 CPUC 2d 256, 260-261)

Neither, however, do we consider complete abandonment of the A&S long-term contracts a prudent course. Rather, the proper goal is an appropriate balance between long-term and short-term gas supplies that blends the goals of low price and supply availability. While there was supply uncertainty with respect to alternative Alberta supplies, PG&E was able to cope with such uncertainty without jeopardizing core supply during peak-demand periods. Thus, we conclude that PG&E had prospects for procuring Canadian short-term gas in excess of 700 MMcf/d through aggressively exploiting existing competitive forces.

E. Supply Reliability Beyond the Record Period

1. Would Reducing A&S Gas Takes on a Temporary Basis Have Jeopardized PG&E's Ability to Protect Core Customers' Long-Run Supply Security?

a. Positions of Parties

In the previous section, we addressed concerns over supply security relative to meeting core peak demand during the record periods. PG&E further raises the issue that reduced takes in A&S gas would have jeopardized core customers supply reliability in the future, beyond the end of the record periods. PG&E argues that any action resulting in A&S reducing its firm takes in 1988 or 1989 would have been imprudent given the substantial demand for Alberta gas by other markets. In particular, PG&E asserts there were substantial new demands for Alberta gas from eastern Canadian LDCs and U.S. buyers in the Midwest and Northeast both prior to and during the record periods. PG&E contends that had A&S reduced its firm takes, A&S reserves currently contracted for PG&E's customers might have been reclaimed and sent to the northeast, seriously jeopardizing PG&E customers' future supply of Canadian gas. This risk was of particular concern according to PG&E because of a growing perception that short-term gas surplus deliverability, referred to as the "gas bubble," would dissipate by the early 1990s.

Thus, LDCs generally began to sign more long-term contracts, according to PG&E, to protect themselves from supply interruptions, price volatility, and the general uncertainty related to spot sales in the event of future tightening of supply. In response to competition from declining fuel oil prices by the mid 1980s, gas prices likewise dropped. Gas production accordingly declined in response to dropping gas prices. Yet, as production declined, demand increased by 2.5 Tcf between 1986 and 1990.

b. Discussion

To the extent PG&E was justified in believing during 1988 and 1989 that the "gas bubble" would end by late 1990, we conclude it is unlikely that existing A&S reserves would have been confiscated unilaterally absent a violation of contractual terms governing A&S gas takes. If PG&E had expressed a good faith willingness to take full firm volumes under Service Agreement and International Contract at prices competitive with alternative competitors (including Alberta competitors), but A&S producers had refused, then PG&E/A&S would still be contractually entitled to the full amount of licensed reserves. Even had the Canadian government redirected licensed volumes for gas not taken, this would only have involved volumes which at the margin served core elect customers who were only committed to the core on a year-to-year basis, anyway. Such action would not have jeopardized reserves dedicated to captive core customers who would be the ones for whom long-term supply security would matter.

It is questionable in any case whether A&S producers would have been eager to reassign permanently their reserves to other markets where netbacks might not be as profitable as could be had through its 25-year contract with A&S. Moreover, the ultimate end of the gas bubble did not necessarily mean that alternative gas could no longer be found. PG&E's own witness characterized the "end of the gas bubble" as "essentially the overall supply availability coming into line with the demands forecast." (Seedall/Tr. 8033.) SMUD's witness further elaborated that the end of the gas bubble did not mean supply shortages, but rather an equilibrium of prices rising to meet increased demand. (Tussing/Tr. 4611.)

We also acknowledge the growth in the Canadian/U.S. export markets throughout the record periods, but do not view this growth as evidence of a future threat to PG&E's access to gas. Rather, we view it as further evidence of the abundance of Canadian supplies being marketed aggressively by Canadian producers in the U.S. in response to relaxed governmental price controls. Our view is supported by the observations of one of PG&E's own witnesses in an excerpt from his November 1988 presentation before the Petroleum Industry Research Associates (PIRA) where he stated:

> "Now most governmental constraints have been removed and, barring any reintroducing of controls, Canada's share of the U.S. gas market should grow substantially. Our forecast...has Canadian gas export volumes nearly doubling over the next twelve years. Export growth will easily outpace the expected volume increase in U.S. demand." (Exh. 1128, p. VIII-1.)

Moreover, even to the extent we were to assume that the end of the gas bubble would have risked core delivery shortages, the A&S long-term gas may have offered limited protection only in certain circumstances. As PG&E's witness noted, even long-term A&S supplies can be diverted to other markets under severe weather conditions, as in February 1989 when Canadian domestic gas needs preempted gas bound for California. (Seedall/Tr. 8039-40.)

2. Effects of A&S License Extension and Contracting Practices on Supply Reliability and Take Requirements

a. Positions of Parties

Alberta gas sold in the U.S. requires either an export license or short-term order issued by the NEB. DRA faults PG&E for its role in extending and increasing A&S's contractual obligations to Canadian producers for allegedly excessive quantities of gas between 1986 and 1990. While the contracting and license extensions referenced by DRA essentially impact supply commitments beyond the 1988-90 record periods, the management decisions to enter into such commitments were made before and during the record periods. As such, DRA views them as further evidence of the sort of anticompetitive behavior that foreclosed opportunities for open access and lower priced Canadian supplies during the record periods. DRA also contends that PG&E's overcontracting has a direct bearing on the pass-through of "transition costs" associated with contract restructuring subject to recovery in a future proceeding.

DRA asserts that PG&E failed to take advantage of various options A&S presented in 1986 to reduce contract obligations to prepare for the competitive restructuring of the California gas supply market. Instead, A&S took the business risk of increasing contract obligations in an apparent attempt to lock up the California gas market for the future. Then, to mitigate A&S's oversupply problems, PG&E allegedly denied ratepayers access to cheaper Canadian gas supplies and shifted the costs and risks of A&S's unregulated gas marketing activities to PG&E's regulated gas utility, according to DRA.

In 1986, A&S applied for and received authority to export through 1994 full PGT pipeline volumes of 1023 MMcf/d. A&S's export license had been previously scheduled to expire in 1993 and authorized volumes were to phase down from 1023 MMcf/d in 1990 to 122 MMcf/d by 1992/3. Since A&S's contractual obligation to producers was explicitly linked to the term of the export license granted by the NEB, an extension in the export license effectively extended and increased A&S's contractual obligations to Canadian producers. Instead of using the scheduled supply phase-out as an opportunity to totally reform its Canadian supply arrangements beginning in 1990, A&S obtained an export license extension for full pipeline volumes until 1994.

To support its license extension, A&S had 8.6 Tcf of Canadian reserves under contract. In 1987, A&S filed for another license extension from 1994 to the year 2010 at full pipeline volumes. In June 1989, the NEB granted the export extension, but only through 2005. Between 1987 and 1990, DRA asserts that A&S

doubled its volume of gas under long-term contract, and extended the term of all pre-1986 contracts to the year 2010.

DRA further asserts that as of May 1986, A&S was already seriously overcontracted in that its supplies were nearly double the average annual demand in 1985. DRA argues that during 1985-90, A&S's aggregate DCQ remained above 1600 MMcf/d, with a high of 1828 MMcf/d in 1990. Thus, A&S's contractual obligation under its pre-1986 contracts already exceeded PG&E's 1066 MMcf/d sales entitlement on PGT. It further exceeded PGT's TOP obligation under the International Contract. Thus, between the TOP recovery mechanism and A&S's contract obligations, DRA believes A&S producers were guaranteed continued high takes to the exclusion of non-A&S Canadian supplies.

PG&E states that its contracting practices and license extension application were prudent and necessary for long-term supply security. Moreover, PG&E contends that full takes from A&S suppliers were necessary to avoid jeopardizing the A&S export license extension. The renewal of the license assured continued security for the core portfolio.

PG&E dismisses DRA's allegations of overcontracting as being based on: (1) an inaccurate assessment of A&S's Canadian supply situation; (2) an inaccurate projection of PG&E's core customers' demand due to DRA's misinterpretation of A&S documents and selective use of other information; and (3) DRA's misreading of Commission decisions and individual Commissioner's statements.

PG&E criticizes DRA's claim that its 1986 supplies were nearly double average 1985 annual demand as being based on an inconsistent comparison of peak versus average data. Given a consistent comparison, PG&E argues that its contracting was in line with demand requirements, particularly when upstream Alberta demand is considered.

PG&E faults DRA for failing to distinguish total contract DCQ from the "effective DCQ" which is adjusted for actual productive capacity. Deliveries have to be discounted by 150 - 200 MMcf/d to calculate the effective DCQ. Thus, DRA's comparison of A&S's "total contract deliverability" of 1,450 MMcf/d with the 1,828 MMcf/d DCQ figure mixes apples and oranges, according to PG&E. When A&S's effective deliverability between 1987 and 1990 is compared, the difference is only 1,450 versus 1,650 MMcf/d.

PG&E asserts that the A&S export license extension was prudent, and any attempt to export short-term gas would have jeopardized both the existing export license and the license extension. Any such short-term exports would have directly displaced gas that would have otherwise flowed under the relevant A&S long-term export license. PG&E argues that such displacement would have led to denial of A&S' 1987 application to extend its export license to 2010 and to increase the volumes authorized for export thereunder. The NEB's Criterion 4 required exporters to demonstrate "that export arrangements provide reasonable assurances that volumes contracted will be taken..." In PG&E's view, the NEB would have likely concluded that A&S could not reasonably assure that it could meet this criterion in the event A&S or PG&E had displaced contracted volumes underlying its existing export license with short-term purchases, and accordingly would have denied the export license extension. Likewise, PG&E warns that even A&S' then-existing export license could have also been jeopardized by such displacement. Under Section 21 of the NEB Act, the NEB has the power to "review, vary or rescind any decision or order made by it..." either on application or by its own motion.

Because of perceived competition for export licenses from LDCs in the U.S. northwest and midwest, PG&E sought an export extension before supplies tightened and more stringent contract terms might be needed to secure the reserves. According to PG&E, producers, the Province of Alberta, and the NEB wanted assurance of a long-term market covering a 15 to 25-year contract period over which to amortize the up-front investment costs in facilities required to gather, process, and transport the gas subject to the export license. Thus, A&S entered into "development contracts" to support the extension which allowed producers to time their exploration and production investments in a staged manner, compatible with A&S's projected need for new gas production in the 1990s.

PG&E and IPAC allege that the goal of extending the import license was supported by California regulators. PG&E and IPAC point to the a letter dated October 21, 1988 from former Commissioner Hulett to the Canadian NEB as evidence of our support for the extension of the export license. In the letter to the NEB, then-President Hulett stated:

> "On behalf of the (CPUC), I wish to advise the (NEB) of our full support for the extension of Export License GL-99 being sought by Alberta and Southern Gas Co. Ltd... Because of its reliability, stability, and current competitiveness, the A&S supply has allowed PG&E to assemble a gas supply portfolio which is very competitive under the market-driven regulatory framework the CPUC has encouraged.... The extended export license will assure an additional sixteen year supply of gas at a time of difficult transition in California markets... For our part, my fellow Commissioners and I wish to assure the Board of the CPUC's continued desire that A&S remain a major supplier of energy for California both in the near term and for many years to come..." (Exh. 1007, p. 2-139.)

PG&E also quotes a similar letter from the Chairman of the California Energy Commission. PG&E and IPAC thus believe it would be fundamentally unfair for us to express criticisms now of PG&E's export arrangements for which we had previously expressed support.

b. **Discussion**

DRA's claim concerning the effects of PG&E's contracting practices on its recovery of transition costs associated with A&S contract restructuring is beyond the scope of Phase IIA.[8] Here, we address PG&E's contracting and export licensing practices only insofar as they bear upon the prudence of its purchases of A&S gas during the record periods.

If PG&E's contracting and licensing actions were imprudent, we must consider whether such actions impeded PG&E's flexibility in procuring cheaper alternative gas supplies. On the other hand, if PG&E's contracting and licensing practices were essential to meet its long-term service obligations, we must consider whether displacement of A&S pool gas with spot gas would have jeopardized the license extension.

DRA's criticisms of A&S's license extension and alleged overcontracting are drawn from a May 1986 internal briefing which A&S officials made to PG&E concerning the future of A&S licensed reserves. A&S noted in its briefing that gas volumes from a large proportion of its 20-year-old Canadian reserves were experiencing age-related decline in deliverability. The rate of decline meant that by the early 1990s, A&S's total deliverability from existing fields would fall below the expected PG&E demand for Canadian gas, then forecast to be 40% of total requirements. A&S warned PG&E that unless it took action to offset the observed and

8 On July 12, 1993, the FERC issued an "Order on Compliance with Restructuring Rule and Related Offer of Settlement" in Docket Nos. RS92-46-000 and RS92-46-002 adopting a settlement as to the manner of recovery for PGT's restructuring transition costs. As part of the settlement, the Supporting Parties (including the CPUC) waived prudence issues (except magnitude of settled costs in relation to liability) relating to transition costs. However, the CPUC did not waive non-prudence issues (e.g. eligibility issues) in that settlement.

expected deliverability declines, A&S would likely be unable to reliably meet the needs of PG&E's core customers by 1990. Thus, while DRA interpreted the briefing as sending the message that A&S had "plenty of gas through the year 1994," the message was rather a warning of the need to secure additional reserves and related export authorizations to meet projected needs of core customers.

DRA misinterprets the A&S presentation by inferring that it was discussing an excess reserve situation. A&S presented options whereby alternate gas markets could be pursued as a contingency to protect PG&E's core market. The alternate markets would presumably ensure against the release of gas reserves which A&S needed to satisfy PG&E's core demand if PG&E's market were suddenly reduced. The intent of such alternate markets was to manage supply already under contract for PG&E's needs, <u>not</u> to contract for added reserves to support a broader marketing effort. Although DRA initially characterized the May 1986 presentation as portraying a supply surplus, upon cross examination, DRA conceded that A&S was actually expressing concern over a supply deficiency. (Tr. 5403:18-24.)

DRA's claim of overcontracting based upon an excessive A&S DCQ relies on an inconsistent comparison. DRA compares A&S system average day demand of 800 MMcf/d with the DCQ of 1460 MMcf/d. A more appropriate comparison is between <u>peak-day</u> demand of 1500 MMcf/d and the DCQ of 1460 MMcf/d. The peak-day demand measures gas volumes required to serve expected maximum demand under cold weather conditions. The DCQ, in turn, represents the amount of gas that a buyer can expect at any given time throughout the year. Even if PG&E sales to noncore customers were reduced, peak-day demand would remain at or near the same level since it is primarily core load.

The fact that the A&S DCQ of 1460 MMcf/d exceeded the PGT pipeline capacity of 1023 MMcf/d is understandable in light of the total A&S peak-day system demand which averaged between 1410 and 1570 MMcf/d during the record periods (Exh. 1103, p. 2-13; Exh. 1072, p. GB-6). To meet PG&E's needs, A&S needed to contract for an incremental amount of gas beyond the PGT peak demand to accommodate upstream commitments and operational constraints. Alberta regulations required buyers of Alberta gas to be able to supply Alberta core customers as a first priority. In addition, contracted gas volumes had to be sufficient to allow for operational constraints such as compressor fuel use, lost and unaccounted-for gas, and gas shrinkage.

Although PG&E's license extension application would seem necessary given the size of its core portfolio requirements, we question a key premise behind its projections. A&S's assessment of PG&E's long-term supply requirements was premised on a need to enter into 20-year obligations to procure gas for core-elect customers. Because core elect customers represented such a significant share of the core portfolio, this premise had major consequences for the need for the A&S license extension.

There was uncertainty as to the long-term continuation of the core elect market as gas industry restructuring continued to evolve. As we stated in D.88-12-099:

> "Ultimately, our long-term perspective on core election is dependent on how the market develops once our capacity allocation program is in place. What happens once access to firm transportation is increased will determine the future need for options such as core election. The market may develop new mechanisms for aggregating gas supplies which, like core election, provide to all gas consumers the benefits of competition among gas supplies and among alternate fuels." (30 CPUC2d 545, 560.)

PG&E should have taken this uncertainty into account in pursuing its licensing and contracting activities aimed at serving the core elect market. While core election represented a useful tool to tap competitive market forces during the initial years of gas industry restructuring, there was no assurance it would be the best solution over the long run nor that it would continue indefinitely. Yet, PG&E's contracting and licensing practices were premised on the long-term continuation of the core elect option while the actual duration of this option was subject to expiration on a yearly basis. At the end of the year, core elect customers could revert to being noncore customers and decline to buy gas from PG&E, leaving PG&E with an unneeded surplus. We had specifically warned as early as 1986 in D.86-03-057:

> "The ability of the non-core customers to leave the retail system at any time for any duration means that the utility should not incur any sort of fixed payment obligations with its suppliers for securing gas supplies on their behalf unless the non-core customer signs service contracts with the utility to pay for such obligations...
>
> "...[A] utility no longer should be obligated to seek long-term supply for those [non-core] customers unless they are willing to sign long-term service contracts for gas with the utility." (20 CPUC 2d at 633-634.)

Although core elect customers signed one-year service contracts with PG&E, this was far short of the 20-year duration of the fixed payment obligation with A&S producers underlying the one-year service contract. Although the longer term uncertainty of core election was information available throughout the record periods, impending changes in core election policies grew more imminent as PG&E entered the 1990 record period. In its March 14, 1990 internal memo, PG&E management noted:

> "[S]hould the CPUC limit PG&E's merchant role, the take obligations associated with [the A&S supply contracts] may become impossible to meet, and the Company's gas supply commitments could then represent a significant potential liability...

> "[The contract commitments to 2005] was predicated upon the CPUC's previous gas industry restructuring, which strongly affirmed the utilities' role in procuring gas for UEG and noncore customers that desired such service...(Exh. 1120, p. 2)."

Accordingly, we conclude that while PG&E was prudent in contracting and securing export licenses for volumes associated with captive core customers, it was not necessary to commit itself for up to 20 years for additional reserves to serve core elect load. By doing so, PG&E unnecessarily limited its flexibility to seek competitive alternatives to benefit all ratepayers. Accordingly, we are unpersuaded by argument that attempts to procure short-term supplies would have jeopardized an application for licensed volumes for which there was no corresponding service obligation.

The remaining question is whether the existing A&S license would have been threatened by reduced takes; and if so, would core customer supply security have been threatened?

We do not find any conflict between efforts to pursue an export license extension for captive core volumes and the procurement of spot gas for a portion of Alberta supplies. The question is what core volumes are essential for export licensing over the longer term. Given the limited year-at-a-time duration of core elect load, we find no compelling requirement that PG&E had to include such tentative core elect demand in a license extension covering a 20-year period.

The strategy of taking spot gas proposed by DRA/SMUD would only apply to volumes above the 50% minimum level. PG&E could have taken such a strategy into account in its export license extension application by including a reduced volume of reserves sufficient to cover captive core demand projected over future years. Thus, PG&E would have been able to satisfy Canadian authorities that its demand for gas was sufficient to cover licensed volumes for such captive core needs.

We find former Commissioner Hulett's letter offers little or no justification for the necessity of the A&S export license extension at the expense of cheaper alternatives. We previously rejected PG&E's arguments concerning the significance of the Hulett letter in D.92-07-078 in which we denied PG&E's motion for summary judgment. In that decision, we concluded that PG&E failed to meet the burden of convincing us that it somehow was misled by the Hulett letter into believing its actions had been found reasonable this Commission. PG&E should have been aware that a letter authored by a single Commissioner did not constitute an official Commission action as defined by statute (PU Code § 306; Gov. Code Sec. 11120, 11122, 11132). As we stated in D.92-07-078: "It is the essence of understatement that we are not persuaded that the movant's burden has been discharged by reliance on a piece of correspondence authored by a single Commissioner." (p. 22).

Moreover, the standard for judgment of PG&E's reasonableness is not what individual Commissioners or the Commission as a whole believed concerning PG&E's licensed gas reserves in October 1988. The proper standard is what PG&E, itself, knew or believed at the time when decisions were made. Expressions in the letter were made without the benefit of an evidentiary record as to the reasonableness of 1988 record period gas costs or as to any anticompetitive activity as subsequently alleged by parties.

Thus, we do not find any impediments to PG&E's procurement of spot gas as a result of concerns over its license extension.

F. <u>Canadian Government Impediments</u>

Parties dispute the significance of Canadian governmental intervention in gas market transactions as to whether such actions would have either (1) prevented PG&E from implementing any of the procurement stategies set forth by DRA/SMUD/TURN or (2) at least diminished PG&E's relative market power in bargaining aggressively with Alberta producers.

During the record periods, the Canadian government exercised authority over gas exports at both the provincial and federal levels. The Canadian federal government regulated the export of gas to the U.S. through the issuance of export licenses by the National Energy Board (NEB). The Province of Alberta regulated gas sales through the use of removal permits which are required before any gas volumes can be removed from the province.

The Alberta provincial government both owned the gas and controlled the terms under which provincial gas may be exported to the U.S. Thus, it had an economic interest in regulating gas sales in a manner which was in the overall best interests of the Canadian government.

Although the Canadian government introduced market-sensitive gas pricing during the mid-1980s, it continued to exercise regulatory control over the terms by which gas could be transported and exported from Canada to the U.S., according to PG&E. PG&E argues that because of its ownership interest, the Canadian federal and Alberta provincial government would have actively impeded efforts on the part of PG&E to displace A&S long-term gas with cheaper substitutes. We have already addressed the Canadian government's role in gas exports somewhat. In the following sections, we address the remaining claims of Canadian governmental impediments to purchase of cheaper gas supplies.

1. Would Canadian Governmental Authorities Have Intervened to Prohibit PG&E From Displacing a Portion of A&S Gas With Short-Term Gas?

a. Positions of Parties

PG&E asserts that any attempt to export substantial volumes of Canadian gas to displace sales that would otherwise occur under long-term arrangements would not have passed Canadian regulatory scrutiny.

The export of Canadian gas requires both provincial removal permits and federal export licenses by the NEB. The Alberta Gas Resources Preservation Act, as modified October 30, 1986, prohibits the removal of gas from the province, except under the authority of a permit issued under the Act. A removal permit requires the approval of the Alberta Energy Resources Conservation Board (ERCB), the Alberta Department of Energy, and the Minister of Energy. Removal permits require a finding that the proposed sale is in the provincial public interest. The ERCB may also suspend or cancel a removal permit at its discretion if it concludes it is in the public interest of Alberta to do so. Under the provisions of the NEB Act - Section 118, the NEB applies a "Market-Based Procedure" which considers among other things, evidence of producers' support for the proposed export, whether provincial removal permits had been granted or were forthcoming, and whether long-term sales contracts assuring the gas would be taken by the applicant were in place.

PG&E further states that the NGMA formalized the requirement for producer support for downstream pricing under netback pricing arrangements. PG&E argues that A&S producers would not have supported a price lower than what was paid by PG&E, and could have effectively blocked any strategy to sell gas under different terms than what was actually paid during the record periods. Part 2, Section 9 of the of the NGMA prohibits the removal from Alberta of "netback gas...during any period after the prescribed deregulation date...unless there is in effect during that period a finding of producer support in relation to that netback gas." A finding of producer support would be issued by the APMC only after it had determined that a shipper had "obtained the prescribed minimum degree of support of the producer of the netback gas for the resale of the netback gas..." as established under the

Natural Gas Marketing Regulation. (Exh. 1025, p. 4-23.) As amended in 1989, it required support of a minimum of 50% of producers having at least 60% of contracted volumes. The APMC was empowered to impose significant financial penalties on any shipper who removes or resells netback gas without the requisite producer support.

In 1984, the NEB adopted an export approval criterion that the export price must at least equal the price of major competing energy sources in the consuming market. PG&E therefore argues that the NEB would have denied an export license for volumes priced below what PG&E was then paying to competing suppliers. PG&E finds this criterion to be similar to the U.S. DOE and ERA import criteria. PG&E faults DRA/SMUD for failing to explain how the NEB would have applied this export price criterion to allow an export license at the prices posited in their proposed disallowance scenarios.

In its March 1987 <u>Report on Gas Supply Protection</u>, the ERCB stated its intention to monitor "permits under which removal volumes are substantially less than approved by the permit..." The ERCB further stated: "Where surveillance indicates that removals are not in accordance with the relevant permit, the ERCB will take action which may include reviewing and amending or rescinding certain permits." Thus, PG&E argues that a substantial displacement of its long-term volumes with spot gas would have jeopardized its removal permit.

PG&E states that the Alberta Permit Conditions Regulation requires the approval of the Alberta Minister of Energy for any change from arrangements filed with the Minister for marketing gas outside Alberta. Any short-term removal permit would require such approval. Any amendment of A&S's gas sales export contract with PGT, arising from purchases by A&S in the Alberta spot market, would have required the approval of the Alberta Minister. PG&E believes that in the absence of support by the A&S

producers, the Minister would not have given such approval. Faced with the prospect of lower-priced spot sales displacing their long-term sales, PG&E finds it highly unlikely that A&S producers would have given such consent.

PG&E contends that the Alberta government applies a "core market policy" whereby core markets served under long-term contracts must first be served with long-term gas taken under those contracts. PG&E also contends that under the Alberta government's policy against allowing short-term sales to displace long-term sales to LDCs, it would have been unable to remove short-term quantities of Canadian gas. Canadian authorities would have denied a removal permit under this policy. PG&E quotes the APMC testimony before the Manitoba Public Utilities Board:

> "Removal of natural gas from Alberta for sale to a distributor will only be allowed if the distributor is taking full volumes, on a daily basis, under all natural gas contracts entered into by the distributor and in force on October 31, 1985..." (Exh. 1025, p. 4-15.)

In its opening brief, the APMC objects to PG&E's characterization of the Canadian government as having the ability to exert market power and to discriminate among markets in the pricing of its energy resources. APMC describes the role of the Alberta government as simply being interested in ensuring that a balanced negotiation is possible between buyers and sellers. The APMC disputes PG&E's allegations that intervention by Alberta or Canadian authorities during the record periods would have been inevitable had PG&E tried to pursue DRA's suggested purchasing strategy. APMC calls PG&E's assertions purely conjectural.

While IPAC believes that the A&S producer pool transactions were reasonable on a commercial basis, IPAC does not support PG&E's contention that Canadian regulatory authorities would have blocked PG&E if it had attempted to implement any of the DRA/SMUD alternatives. IPAC contends that there were no Canadian federal or provincial actions during the record period which can be shown to have had the effect or intent of preventing PG&E or any other party from engaging in spot gas transactions. No Canadian government actions prevented PG&E from obtaining the lowest price for gas which the market would permit and which conformed to PG&E's contractual obligations, according to IPAC.

DRA also concludes that there is no factual evidence to support PG&E's assertion that intervention by Alberta or Canadian authorities would have been inevitable. SMUD believes that if PG&E had started in the mid 1980s to move towards a competitive market rather than further increasing its dependence on the A&S pool that it could have avoided the contentious environment that has more recently developed between PG&E and the Canadian authorities over the restructuring of PG&E's supply contracts.

2. **Would PG&E Access to Upstream <u>Pipeline Transport Be Cut Off</u>?**

a. <u>Positions of Parties</u>

In order to consummate a purchase of Canadian gas outside of the A&S producer pool, PG&E would have required access to transport on upstream Canadian pipeline facilities north of the import point at Kingsgate, B.C. The link from the international border to the Alberta-British Columbia border is made by Alberta Natural Gas Company (ANG), pipeline regulated by the NEB. The transport link to the various field gates within Alberta is made through NOVA.

Firm transportation on all of the Canadian pipeline facilities sufficient to accommodate the A&S/PGT/PG&E sales was held by A&S during the record periods. According to IPAC (Schissel), A&S transportation rights on upstream pipelines were obtained on the basis of A&S gas supplies to facilitate the sales transactions between A&S producers and, ultimately, PG&E.

If PG&E reduced its takes under A&S producer contracts, the A&S producers would seek alternative markets for gas not taken by PG&E. The producers would still need firm transportation on NOVA and Albert National Gas Pipeline (ANG) to deliver their gas to other markets.

PG&E and IPAC claim that the producers, and not A&S, would be the likely candidates to receive the associated NOVA/ANG transportation rights, if PG&E tried to bypass A&S producers. Since the federal and provincial governments of Canada regulated the terms under which gas was transported over NOVA and ANG, these regulators would have given preference to A&S producers over A&S in assigning firm transport rights.

In support of this contention, PG&E cites Canadian government actions which have occurred since the close of the 1990 record period. In June 1991, the Alberta provincial legislature enacted Bill 41 to amend the NGMA to extend the netback pricing agreements of any designated shipper where such agreements would otherwise have expired. This initiative was taken on the eve of the expiration of the netback pricing arrangement between A&S and its producers.

PG&E also cites the published announcement of the Alberta Minister of Energy on December 3, 1991 in response to our Capacity Brokering Decision. The Alberta Minister announced the Alberta government's intention to "introduce legislation to ensure that firm transportation rights of the A&S supply pool under existing contracts are not undermined by regulatory decisions in California." (Exh. 1025, p. 4-40.) The measures were intended to prevent interruptible service on NOVA from "undermining current long-term supply arrangements."

DRA and SMUD contend that A&S could have retained its rights to upstream transport capacity and could have used them on behalf of PG&E to purchase alternative supplies. A&S, not the producers, owned the upstream firm transport rights on ANG/NOVA. Thus, DRA and SMUD conclude that PG&E, as the parent of A&S, could have directed A&S either to transfer its firm transport rights to

PG&E or to utilize such transport rights on behalf of PG&E to procure alternative Canadian supplies (Tr. 3852:16-28). Since PG&E's ratepayers ultimately pay the upstream A&S pipeline demand charges in the PGT tariff, it is fair that they be the recipients of the transport rights, in preference to A&S producers, according to DRA (Tr. 3850).

3. **Discussion**

We do not find that the Alberta government ownership interest in gas reserves or its regulatory authority over exports constitutes compelling evidence that it would have prohibited short-term sales transactions between PG&E and willing sellers of gas. As noted by APMC, Alberta does not itself develop, produce, or market its natural gas resources any more than does the U.S. Federal Government on offshore lands where the latter owns the resources. It does not follow that simply because of its stewardship role, Alberta could or would have engaged in discriminatory price behavior to interfere with free market negotiations between A&S and independent Alberta producers. PG&E's witnesses themselves testified that at no time during the record period or before did the Province of Alberta attempt to control the export of gas to PG&E's market in a manner intended to maximize revenues (Tr. 7332).

There is no dispute that short-term removal permits would have been required to export spot gas from Canada and that the Canadian ERCB had authority to deny such permits. The question is would such permits have necessarily been denied had PG&E followed a different strategy from 1988 forward? We do not believe denial of short-term removal permits was inevitable, assuming PG&E had entered into freely negotiated pricing arrangements with Alberta producers.

We acknowledge the remarks of the Alberta Minister of Energy and Natural Resources in September 1986 that the ministry was "not going to allow gas from Alberta to be removed at fire-sale prices or at prices below market value." The remarks in question were a portion of the Minister's answer to opponents of a bill the government was sponsoring, and merely replied in the same words the opponent had used. The bill the Minister was defending liberalized the removal permit process by deleting a mandatory economic assessment requirement and a public hearing requirement from the process in order to assure that there would not be accusations of government interference in free-market negotiations concerning price. (Exhibit 1415.) We are not convinced that PG&E was so powerless that any strategy short of the one it pursued would have been stymied by Canadian government interference or that the Canadian government would have refused to authorize short-term removal permits under any circumstances.

PG&E's examples of Canadian government intervention in commercial gas export negotiations all occurred in instances where there was violation of the terms of contracts or permits or else where prices were not based on market forces. For example, PG&E's citation of 1989 NEB denials of various applications for export licenses does not persuade us that the NEB would have likewise have denied an export license application by PG&E (Exh. 1025, pp. 2/32-34). These denials were based upon pricing arrangements which were not market based over the entire contract term. Yet, a PG&E-negotiated price which took into account competitive market forces within Alberta would most certainly have been market-based.

Likewise, the NEB's imposition of an interim price increase on A&S and implicit time limits on negotiations in April 1989 (PG&E Opening Brief, pp. 156-157) was aimed at inducing parties to reach a mutually agreeable settlement in a timely manner, not in imposing any particular price from the outside. Thus, this example does not support a conclusion that the NEB would have stopped PG&E from negotiating a more competitively priced alternative arrangement. We believe PG&E could have worked within the framework of the existing supply contracts to invoke intra-Alberta competition, as discussed in Section V.A.

We find limited evidentiary value in the examples of Canadian government pronouncements and intervention after the 1988-90 price redeterminations had occurred. A major criticism which PG&E/IPAC/CPA have made of DRA/SMUD's case is that it relies on hindsight and presumes conditions which only came into being after the close of the record periods under review. While we agree we must limit our review to contemporaneous record period events, such limitation must be applied consistently to the evidence presented by all parties. The post record period examples of Canadian government intervention were in reaction to regulatory decisions we issued after 1990 in our effort to enhance competitive access to Canadian gas supplies for the benefit of PG&E's customers. The relatively contentious climate which developed after the record periods is not necessarily one that would have existed in early 1988. This can be seen, for example, in the NEB's statements issued in its June 1992 "Reasons for Decision in the GH-R-1-91 proceeding" in which it decided to preclude exports of non-A&S gas and suspend interruptible service. The NEB stated therein: "The Board believes that the CPUC decisions and not market forces will affect the manner and extent to which gas will flow under these contracts which were negotiated in good faith. Moreover...the effect of the CPUC decisions is to extend its jurisdiction beyond the boundaries of the State of California." (Exh. 1682, p. 24.)

Likewise, the Alberta Minister's December 1991 statements cited by PG&E were reacting to the then-recently issued D.91-11-025 regarding capacity brokering. The Minister perceived the CPUC's decision as threatening to "undermine the current [A&S] long-term supply arrangements..."

The above-quoted comments of Canadian governmental authorities were issued beyond the end of the 1990 record period and apply to a different time frame and set of events than those which we believe PG&E could have pursued during the record periods.

It is not appropriate to extrapolate subsequent period actions of Canadian governmental authorities backward to the record periods when the regulatory climate was at a different stage. As SMUD's witness observed:

> "If PG&E and A&S had started a transition in the mid-to-late 80s towards open access and securing short-term supplies, rather than extending long-term supplies of gas from Canada, and made those representations to the Canadian government, I don't think it would have been necessary for the Canadian Government to take this type of action at this time..." (TR. 6793.)

PG&E's examples of Canadian government intervention are based upon a contentious atmosphere that was exacerbated because PG&E did too little too late in moving towards a more competitive market environment. PG&E should have established the premise that the producers must acknowledge price competition north of the Canadian border.

PG&E could have set a different tone for how gas restructuring was to apply to its A&S supplies by more aggressively initiating the core election option in 1988 price renegotiations. PG&E did advise A&S producers in its 1988 commodity rate analysis that: "A high core election level decision by the power plants would in itself increase the core portfolio size by as much as 50%. The extent to which PG&E's power plants choose core portfolio service will depend on Canadian producer approval of the extension of the $1.81 price." (Exh. 1022.) Yet, in its actual bargaining PG&E failed to use the incentive of core election to establish the Alberta market as a factor in A&S pricing.

While the initial level of core election in 1988 was still uncertain, PG&E could have initially proposed to hold back some portion of its core elect load unless the A&S pool was willing to recognize Alberta market forces in its offer. (See Section V.C.3 for a complete discussion of core election.) If PG&E had initially held back a share of its load from the A&S pool under the bargaining scenario discussed in Section VII.E, we do not believe PG&E would have violated any provision of the existing A&S license. The terms of the export license were linked to the International Contract. As discussed in Section V.A, the terms of the International Contract called for takes beyond 50% only to the extent volumes were priced competitively with alternatives.

We agree with TURN's general assessment that Canadian suppliers were flexible enough to have accepted a price based upon Alberta price competition--albeit grudgingly--had PG&E negotiated more aggressively. In Section VII, we arrive at PG&E market prices which would have recognized competing Alberta alternatives. Had the A&S pool thus agreed to such prices, we do not believe the Canadian government would have challenged it. PG&E's witness Harrison was unaware of any instance where the Alberta ERCB had disregarded a price that was approved through the producer voting mechanism (Tr. 8870:11-17). APMC states there is no evidence to indicate that the NEB would have denied an amendment to the existing A&S license had it been approached, and had producers agreed with PG&E that it was appropriate to replace their long-term sales with short-term sales and negotiate alternative arrangements.

We do not believe the voting mechanism's requirement for a finding of producer support need have been a fatal impediment to PG&E's efforts to stimulate intra-Alberta competition. It was unlikely A&S producers would have lent support simply to sell a portion of their licensed gas to PG&E/A&S on spot terms less favorable than they could expect to get on a long-term price basis, assuming no alternatives to dealing with the A&S pool. Yet, as discussed in Section V.D, there was enough gas potentially available that PG&E could have found producers outside of the pool who would have supplied at least some volumes of short-term gas.

As discussed in Section V.D, Alberta supplies were sufficiently plentiful such that independent producers could have been located to support at least 300 MMcf/d of gas demand. If the A&S pool refused to offer a competitive price for the incremental volumes, PG&E would offer A&S producers a price as outlined in Section VI for the equivalent load of 700 MMcf/d. Since A&S producers would be getting what PG&E has characterized as a "netback" price for these volumes, it is reasonable to expect they would have offered support for export of such volumes through the NGMA netback voting mechanism. As discussed in Section V.A, A&S/PGT would be in compliance with the Equitable Purchase Policy of the International Contract under such circumstances.

As discussed in Section VI, for PG&E's remaining Alberta requirements above 700 MMcf/d, market forces would have given independent Alberta producers the incentive to bargain with PG&E for a share of this increment of gas demand at prices below A&S levels, while still offering profitable opportunities relative to their alternatives. Under the NGMA, PG&E would have had the option of pursuing one-on-one negotiations with independent producers, without the need for collective vote of producers' support. For residual volumes, since they would be procured from independent sources outside of the A&S pool, independent producers would logically support the issuance of a short-term removal permit for such volumes before the Alberta government. Likewise, the approval of the A&S pool would not be relevant for such volumes which would be subject to completely separate contractual arrangements.

The likelihood that PG&E could have secured short term removal permits for gas exports as outlined above is further supported by the statements of PG&E's witness Lawrence, quoting again from his November 1988 presentation before PIRA:

> "1987 marked the turning point. This was the year that Canadian Government controls on export prices and short-term authorizations were effectively removed. Now an exporter could set the price of gas based on market

> conditions and not be constrained by an unrelated official price. <u>And getting approval for short-term export volumes became perfunctory.</u>" (Emphasis added.) (Exh. 1128, pp. VIII-3/VIII-4.)

PG&E's witness Ziff also testified that the Canadian government historically has not exercised its power to intervene in commercial negotiations, even though it has such power:

> "Quite clearly, the power is there for the government. Also, quite clearly, the past practice has been that it's not been exercised in the past. I have difficulty saying it would never be exercised. I think if it were to be exercised, there would have to have been an issue of principle. For instance, a radical departure from end use consumer market pricing, perhaps effected by actions beyond the boundaries of Alberta, that could lead the Alberta government to a different type of action." (Ziff/Tr. 8585-8586.)

PG&E argues that the Alberta government's "core market" policy would have prevented core market purchasers like PG&E from obtaining short-term gas from Alberta. In fact, the core market policy applied exclusively to sales outside Alberta <u>within Canada</u>, and was intended to <u>protect</u> export sales -- such as those to California -- from the winter-season curtailments which might occur if high priority Canadian domestic consumers were threatened by unavailability of short-term gas and therefore sought to divert export gas to protect human needs and other critical markets (Exh. 1416).

In support of its claim that the Alberta government's policy was against self-displacement of long-term for short-term gas, PG&E cites the Manitoba Public Utilities Board report (Exh. 1025 at p. 4-15). As discussed in IPAC's opening brief (pp. 74-75), this report was based on hearings of which an excerpt of the transcript was introduced as Exhibit 1417, in which it is clearly stated by witnesses on behalf of the Alberta government that its policy was <u>not</u> to deny removal permits where a contract had expired and was renegotiated at a lower price or where the buyer and seller freely negotiated a lower price, but only where a distribution company attempted to walk away from long-term contracts, replacing the gas with short-term purchases from other producers. Accordingly, we are unpersuaded by PG&E's contention that the Province of Alberta's stated "self-displacement" policy would prevent PG&E, from procuring short-term gas prices on a competitive basis. SMUD also disputes PG&E's assertion concerning short-term gas displacement policies. SMUD believes it would have probably violated the Canada-U.S. Free Trade Agreement had the NEB or Alberta government attempted to block exports on that basis.

Moreover, the Alberta Gas Resources Preservation Act (GRPA) in October 1986 eliminated the criterion of whether proposed gas removals were incremental or consisted of the replacement of one Alberta producer by another as seller of the gas. Thus, this amendment helped promote a regulatory environment within Canada conducive to competition among Alberta producers.

Based upon APMC's and IPAC's explanation of Alberta core displacement policies, we find no compelling basis to conclude that the Alberta government would have denied a removal permit to prohibit short-term gas exports to PGT/PG&E from displacing long-term sales under A&S producer contracts, all else being equal.

In determining whether the Canadian government could and would have prevented PG&E/A&S from using NOVA/ANG for transport of non-A&S pool gas, we must consider what transport rights in NOVA/ANG were held and by whom. The firm transport rights on NOVA and ANG legally belonged to A&S, not to the A&S producer pool during the record period. The rights of A&S producers to use NOVA/ANG were integrally tied to their sales rights under contracts with A&S. A&S would have continued to possess those rights absent intervention by the Canadian government to reassign the rights to A&S producers, thus foreclosing other Canadian producers from competing for sales in the PG&E market. Under the NOVA Corporation of Alberta Act (NOVA Act), the provincial government retained the power to supervise the terms and conditions of NOVA service.

The question is what would the Canadian government have done, if anything, to prohibit A&S from using its legal transport rights had it been unable to reach agreement with the A&S pool initially in its 1988 price negotiations for acceptable terms on full licensed volumes? Since PG&E did not attempt to transport alternative Alberta supplies in 1988, we have no record confirming that the government would have intervened to prohibit such sales.

As discussed previously, in spring 1988, PG&E could have presented an offer to the A&S pool, such as that outlined in Section VII, which would have been consistent with the existing A&S pool arrangement. As previously discussed in Section V.A, the existing pool arrangement as renegotiated in 1984 did not contractually guarantee the A&S pool full takes of its licensed volumes. The A&S pool's rights to full takes were contingent on pricing the gas competitively with what PG&E could get elsewhere. If the pool had agreed to accept a competitive price, then we agree that PG&E would have been bound to take full volumes from the pool. In such a case, A&S producers would in fact have a right to the ANG/NOVA capacity as a byproduct of their sales rights. Thus, while PG&E could not expect to succeed in undermining A&S producer's long-term sales rights, neither could producers expect to succeed in undermining PG&E's rights to a competitive price.

Even had the A&S producers sought to obtain control of ANG/NOVA rights in 1988, it does not follow that they would have automatically succeeded. If A&S producers had refused to offer a price competitive with alternatives, then under the international contract, only 50% of contract volumes had to be taken. PG&E could have sought alternative suppliers for the remaining 50% without violating the terms of the contract. Under this condition, we conclude that had PG&E been able to locate alternative Canadian supplies, then it could have gained upstream access on NOVA and ANG by exerting influence over its subsidiary, A&S, to make use of A&S's firm rights to transport such gas on PG&E's behalf.

Finally, if PG&E believed Canadian governmental impediments existed, it never complained to U.S. or Canadian authorities about such alleged governmental impediments. In fact, the evidence indicates PG&E was quite pleased with its A&S price arrangements and did not even consider going outside of the A&S pool, even as a competitive threat. Thus, in consideration of all these factors, we conclude that PG&E has not shown that the Canadian government would have been an insurmountable obstacle to consummating transactions for lower priced gas.

G. Did PG&E's Canadian Gas Prices Reflect Relevant Competitive Market Forces?

Next, we consider the appropriate market price for volumes which could have been purchased in Alberta outside of the A&S pool. Parties present conflicting premises as to the proper criteria for measuring Alberta price competition as it relates to PG&E's market. PG&E, IPAC, and CPA view the proper competitive benchmark for PG&E's Canadian gas purchases as being the U.S. Southwest market prices. PG&E, IPAC, and CPA agree that the prices paid within Alberta or other Canadian provinces, whatever they were, were not available to PG&E during the record period, and thus not relevant as a standard of prudence. They contend the market in which Canadian producers competed generally was the respective <u>buyer's</u> market. These parties argue that Canadian gas exported to the U.S. was priced based upon the competing alternative in the buyer's market. In the case of PG&E, its alternative gas supply outside of Canada during the record periods was from the U.S. Southwest.

DRA/SMUD/TURN, by contrast, view the proper competitive benchmark for PG&E's Canadian purchases as including some recognition of prices paid to non-A&S Alberta producers.

Especially in light of evidence that such Alberta prices were substantially less than A&S prices, these parties believe PG&E was imprudent for failing to factor them into its purchase prices.

In Section V.A, we addressed the contractual and regulatory provisions relating to the definition of the market by which A&S price competition may be measured. In this section, we consider the economic evidence as to the appropriate PG&E market benchmark for pricing alternative supplies within Alberta.

Thus, to resolve the dispute over the price PG&E should have paid for its Canadian supplies, we first consider how competitive its supplies were relative to U.S. Southwest prices. Next, we consider whether the U.S. Southwest or the Canadian producer region is the proper market within which to evaluate the competitiveness of A&S prices. We must further determine what measure of market power PG&E/A&S had as leverage to extract low prices within that market.

1. Significance of U.S. Southwest Gas as a Benchmark for A&S Prices

a. To What Extent Did A&S Producers Discount Prices Below U.S. Southwest Levels

(1) Positions of Parties

PG&E cites prices from suppliers in the U.S. Southwest as the true benchmark against which Alberta producers set prices to PG&E. On the basis of U.S. Southwest prices, PG&E/IPAC/CPA contend that the prices that PG&E paid for A&S gas were quite competitive.

Based on a comparison of recorded U.S. Southwest spot prices with A&S prices, PG&E computes that it saved ratepayers $10.2 million in 1988, $68.5 million in 1989, and $91 million in

1990. According to CPA, on an incremental basis,[9] A&S producer gas was $90 million cheaper than the equivalent amount of U.S. Southwest gas during 1988 and $160 million cheaper each year during 1989 and 1990. If pipeline demand charges are included in the comparison, the savings still amount to $192 million. CPA contends, however, that pipeline demand charges constitute "sunk" costs and are thus irrelevant to purchasing decisions. CPA's comparisons assume a constant 95% load factor on both the PGT and El Paso systems. If actual load factors had been utilized, the average cost for Southwest gas would have risen while A&S gas would have decreased, since A&S gas was taken at a 100% load factor. (Tr. 43:5847-48.)

SMUD argues that PG&E's price comparisons are faulty because they do not account for anomalies in the data. The calculations compare PG&E's prices for Canadian gas with prices that PG&E <u>paid</u> for Southwest gas, not the prices PG&E <u>would have paid</u> had it bought more Southwest gas. By reporting only the prices paid, the data necessarily excludes transportation gas from the Southwest, thus making it impossible to compute the true cost of gas from the Southwest. Further, since PG&E base loaded Canadian gas, it tended to purchase Southwest gas as a swing fuel during winter peaking periods when price would tend to be higher.

(2) **<u>Discussion</u>**

We address the relative significance of U.S. Southwest prices as a competitive benchmark in Section VI.E.

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9 Comparisons on an incremental basis merely consider commodity rate differences between PGT and Southwest producers, but ignore the inconsistencies in rate design between the two. Whereas pipeline demand charges are embedded in Southwest producers' commodity rate, they are excluded from PGT's commodity rate.

b. Were El Paso TOP Surcharges Properly Considered in Determining PG&E's Netback Price Requirement for A&S Gas?

(1) Positions of Parties

PG&E disputes DRA's proposed $33.54 million disallowance related to the El Paso TOP surcharge on the basis that the surcharge was a legitimate cost to include when evaluating alternatives in negotiations with Canadian suppliers. PG&E further notes that the alternative U.S. Southwest market prices were considered in negotiations, but did not form the sole basis for the A&S price. Since the negotiated A&S price in 1990 was 9% below the Southwest price, PG&E discounts the validity of basing a disallowance on a single-cost element considered during price negotiations.

Even if U.S. Southwest prices were the proper basis for developing a netback value applicable to A&S gas, DRA contends that it is improper that the U.S. Southwest price include the volumetric surcharge covering El Paso TOP settlement charges. By including the surcharge in its comparative rate analysis presented to A&S producers during its 1990 annual price redetermination, PG&E caused its ratepayers to pay twice for the same surcharge, in DRA's view: once for El Paso gas, and again in PGT purchases. DRA computes a separate disallowance of $33.54 million on this basis.[10]

10 DRA initially recommended a separate disallowance of $121 million covering the three record periods for imprudent costs on the premise that PG&E unreasonably included the TOP El Paso gas surcharge as a benchmark to derive A&S gas prices. DRA amended its proposal during hearings to cover only the 1990 record period since the El Paso surcharge was not a negotiating element previously, reducing the disallowance to $33.54 million. (Tr. 6337:1-6338:7; 6450:23-6151:4.)

(2) **Discussion**

The proper criterion for inclusion of the El Paso surcharge is whether or not it is a cost which could not be avoided by taking U.S. Southwest gas. To the extent that the charge was volumetric in nature, it was paid only in proportion to the volume of U.S. Southwest gas taken. Thus, assuming that U.S. Southwest prices were the correct standard for determining netback prices for A&S gas, we believe that the El Paso surcharge was a relevant component to include in the analysis. The particular circumstances giving rise to the surcharge were not an issue as long as they were in fact a necessary cost of a choice to take a competing alternative. To withhold the existence of the charge from A&S producers would have been disingenuous and damaging to PG&E's credibility. Accordingly, we reject DRA's proposed disallowance of $33.54 million for El Paso TOP surcharges.

2. Was PG&E Precluded by Market Forces from Procuring Alberta Gas Based on Alternative Prices Within Alberta?

a. Positions of PG&E/IPAC/CPA

According to PG&E, while Canadian gas producers competed against U.S. domestic suppliers for gas sales, they did not compete among themselves by bidding down prices converging towards other Alberta gas sales transactions. PG&E contends that Canadian producers, in general, practiced price discrimination among end-user U.S. export markets, and priced gas in each market based upon the price of competing alternatives outside of Canada, according to PG&E.

In support of its contention, PG&E presents an econometric model analyzing the pricing behavior of Alberta producers selling gas into the U.S. export market. PG&E contends that its model shows that a pattern of systematic price discrimination prevailed during the record periods such that Alberta producers were able to sell gas to different export markets based on the netback value of supply alternatives in the buyers' own end-use markets.

The model is based on U.S. DOE recorded data of over 1,400 gas imports to parties other than PG&E. The model tests the competitiveness of the Alberta export market during the record periods. Applying DRA's assumptions of a competitive Alberta market, the U.S. export price would simply equal a uniform intra-Alberta price plus the cost of transport. Deviations from the uniform price would reflect random differences. The Alberta price would not systematically depart from a constant value in each period. By contrast, under PG&E's price discrimination assumption, the price of individual transactions would reflect each buyer's domestic alternatives. PG&E compared: (1) the price achieved in Alberta for individual spot transactions (the "Alberta Price") and (2) the maximum price that U.S. purchasers would have willingly paid for Alberta gas, given the net value of supply alternatives in their domestic markets (the "Transaction Netback Value").

Under DRA's hypothesis that competition among suppliers was driven by the single intra-Alberta price, one would expect no correlation between the Alberta price and the Transaction Netback Value (TNV). Conversely, under PG&E's hypothesis, if spot prices were influenced by seller market power through price discrimination, one would expect buyers with high TNVs to pay correspondingly higher Alberta Prices. PG&E poses DRA's intra-Alberta price competition as the "null hypothesis" (i.e., the hypothesis to be tested for statistical significance). PG&E applied a statistical "F test" and found that DRA's null hypothesis was rejected even at the .01% level of significance. By contrast, PG&E contends that its model shows "significant" systematic price discrimination existed, based upon end-users' supply alternatives in their domestic markets and the transport distance involved.

PG&E therefore concludes that Canadian producers possessed market power which effectively precluded PG&E from procuring alternative Canadian supplies significantly below the level of its end-use alternatives (which PG&E defines as U.S. southwest gas prices). Customers with higher-priced non-Canadian alternatives would thus be foreclosed from bidding down prices to lower levels.

PG&E contends that it had insufficient market power relative to Alberta producers to have induced them to deviate significantly from their end-user price discrimination. Although PG&E is a relatively large purchaser of gas, its purchases represented only about 13% of total Alberta gas production over the record periods. By contrast, PG&E characterizes Alberta producers as having significantly greater market power, in part through the Alberta government's ownership of 85% of the gas reserves at issue. We separately address the influence of Alberta government intervention in Section V.F.

DRA rejects PG&E's conclusions drawn from its pricing model due to "substantial flaws." DRA expresses four areas of concern. First, to the extent that spatial price differences occurred, such differences do not necessarily prove the predominance of producer market power, as PG&E implies. In support of this conclusion, DRA cites three academic articles (Norman, Greenhut and Greenhut, and Theise and Vives). PG&E notes that these articles deal with an oligopoly market involving only a few firms. With more than 60 sellers participating, the Alberta export market was not an oligopoly. If there are more than a few firms at each location, and the market is competitive, then variations in prices would be solely due to differences in transportation costs. Yet, PG&E's model shows that there were systematic differences which could not be explained solely by transportation costs. PG&E asserts that such systematic differences which cannot be explained by transportation costs are inconsistent with a competitive market.

Second, DRA faults PG&E's model for failing to isolate the effect of price discrimination since the model omits several relevant variables. PG&E responds that its model need not include every aspect affecting North American gas prices to satisfy its limited aim, namely to show a systematic relationship between end-use alternatives and wellhead export prices. PG&E argues that the showing of such a systematic relationship is enough to disprove DRA's assumption of a workably price-competitive market. PG&E also argues that its model does consider seasonal variations in demand, contrary to DRA's complaint that it does not.

Third, DRA complains that the estimation methods used in the model are somewhat inefficient, and the model's parameters reflect instability. PG&E denies that its model's coefficients are unstable; rather, changes in coefficients over time indicate market conditions changes, not model instability.

Fourth, when DRA re-estimated the model by including a nonlinear term, the squared cost of transportation, the measure of alleged price discrimination declined substantially. PG&E faults DRA's re-estimation in that it introduced a multicollinearity problem. Multicollinearity occurs when "independent" variables move together obscuring cause-and-effect links to dependent variables. PG&E found a high degree of collinearity between the squared and linear Canadian and U.S. transportation variables. Due to the resulting instability, PG&E argues that little confidence can be assigned to the individual coefficients.

IPAC and CPA agree with the empirical result of the model that netback prices differ systematically by export market region, but disagree with PG&E's view that such systematic differences indicate lack of a competitive Alberta market. IPAC contends that the varying producer prices to export markets reflected competitively negotiated contracts based on netback pricing arrangements to which both U.S. and Canadian regulators have stipulated. IPAC attributes systematic price differences noted in PG&E's models to structural differences between the Canadian and U.S. market, not to any failure of competition among Canadian producers.

An example of such structural market differences is the role of supply aggregators in assembling packages of smaller supplies which are accessible only to predetermined end-use markets, connected by single long-line pipeline connections. By contrast, U.S. markets are characterized by a large interconnected network of multiple pipeline delivery routes. As IPAC notes, Canadian aggregators frequently used their firm capacity rights to make short-term sales from long-term dedicated reserves to help recover sunk pipeline demand charge obligations in an otherwise weak long-term market. In such cases, aggregators would become price takers in competition with other suppliers to the export market, disregarding other aggregators' prices over other pipelines and export points. Differing end-use prices would result.

Another structural cause of price discrimination could be the relative dominance of long-term contract gas over short-term gas in the Canadian gas market. The available pool of short-term gas supplies could thus become constrained, warranting different prices as a function of consumer value on short-term versus long-term gas. PG&E witness Ziff indicated such market dominance could interfere with short-term supply market price equilibria.

b. Positions of DRA/SMUD/TURN

DRA concludes that an Alberta average spot price is a valid benchmark of market competition applicable to PG&E's Canadian purchase decisions. The source of spot price data used in DRA's disallowance calculation is the price series labelled "Alberta Field Direct" price as published in the periodical Canadian Natural Gas Focus (CNGF). This price series represents spot gas sold exclusively to buyers located within the Province of Alberta.

The comparison of DRA's referenced spot prices with actual A&S prices are summarized below:

$/Dth

(DRA Basis)
CNGF

	Spot Price (Intra-Alberta)	**Actual** A&S Price
1988	0.98	1.73
1989	1.08	1.82
1990	1.02	1.83

Source: Exh. 1101, pp. 135-137.

DRA uses this CNGF spot price benchmark to compute a total purchase cost for Canadian gas based on a weighting of 50% of purchase volumes priced at the Alberta spot price shown above and the remaining 50% priced at the recorded A&S price. DRA contends that long-term contracts track such spot price forecasts. DRA thus concludes that a reasonable price for PG&E's Canadian purchases would have reflected an equal sharing of the differential between the intra-Alberta price and the actual A&S price paid to producers. According to DRA, PG&E was not required to purchase 50% of Canadian gas volumes on the Alberta spot market at the CNGF field direct price, though that is one prudent option. DRA believes an equivalent outcome could have been achieved by taking 100% of A&S contract volumes at a reduced average price reflecting this 50/50 mix, or by any combination of alternatives which would have produced this average price. (Exh. 1736.)

SMUD agrees generally with DRA that spot prices represent the fundamental benchmark against which A&S transactions can be reasonably evaluated. SMUD, however, segments PG&E's prices for Alberta gas into three end-user market groups: (1) PG&E's UEG Department; (2) other noncore customers; and (3) core customers. SMUD assumes that PG&E's UEG Department had been decoupled from core election. Under this assumption, SMUD applies the average publicly reported price in one-year firm direct purchases, resulting in an average price differential of $0.58 for 1988, $0.52 for 1989, and 0.60 for 1990. For noncore customers other than UEG, SMUD assumes they would have procured gas directly from producers or marketers at prices approximating publicly reported spot prices. This yields annual price differentials of $0.64 in 1988 and 1989, and $0.71 in 1990. For the remaining core portfolio, SMUD assumes a price could have been negotiated based upon a 50/50 weighting of (1) the A&S price as paid and (2) the average field price paid by WGML, Alberta's largest aggregator pool and principal supplier of Manitoba, Ontario, and Quebec gas utilities. The annual price differential for the core is thus $0.26 in 1988; $0.30 in 1989; and $0.34 in 1990.

Irrespective of the particular contract duration, however, SMUD believes a spot price benchmark captures the consensus of both producers and purchasers as to overall market value. SMUD believes there is no economic basis for a premium over spot prices in long-term contracts in terms of wellhead supply reliability. The only uncertainty warranting a price premium, would relate to transmission service. Thus, a buyer could reasonably pay a premium for firm versus interruptible transportation.

PG&E, IPAC, and CPA challenge the validity of DRA/SMUD's price proxy assumptions on several counts. Generally, they criticize DRA for failing to account for (1) the dominance within Alberta of firm sales and the relatively small volumes of spot gas actually sold, (2) sales and prices of spot gas to market destinations outside of Alberta, (3) the price effect of large incremental demand for spot gas, and (4) the difficulties in the use of reported or surveyed price data.

PG&E faults DRA's price proxy as being unrealistic in that it is not representative of the overall Alberta market from which PG&E could have procured gas. PG&E, IPAC, and CPA all contend that unlike the U.S., there was not a well-developed spot gas market within Canada during the record periods. The existing pipeline distribution system within Canada was not as developed as was the U.S. system. A Canadian pipeline would not be built unless there were long-term reserves to support it. As discussed earlier, spot sales accounted for less than 5% of the Alberta market. Accordingly PG&E contends that it is unrealistic to use a spot price as a proxy of its own market alternatives.

Moreover, even on the assumption that the spot market were an appropriate competitive benchmark, PG&E contends that DRA's use of the CNGF price data is unrepresentative of the Alberta spot market for export sales to the U.S. DRA's spot price exclusively measures sales to end users within the Province of Alberta. Yet, intra-Alberta transport costs were lower than for sales exported outside the province. DRA's field direct price makes no adjustment for this disparity. PG&E presented statistics showing higher prices prevailed for exported gas. We discuss comparative prices for Alberta exports in Section VI.

The parties also claim that DRA's use of CNGF spot price data fails to represent the market as it would have existed had PG&E attempted to displace A&S gas. As noted earlier, total reported Alberta spot sales according to PG&E barely exceeded 500 MMcf/d. Therefore, IPAC argues that an incremental demand of 500 MMcf/d by PGT/PG&E for spot gas created by displacing A&S producer volumes would have materially affected the balance of supply and demand, causing a corresponding increase, rather than decrease, in the market price of gas.

Parties also note that DRA did not consider the extent to which anomalies in the field direct price data may invalidate their comparability to PG&E/PGT/A&S sales. For example, if the field direct price data included sales to a captive single buyer, the price of such sales would tend to be below what would be representative of sales wherein alternatives were readily available. (Tr. 7046.) Likewise, if sales came from a production field located away from the NOVA system, a shipper would have to absorb additional pipeline transport fees to get the gas to NOVA, thus reducing the net gas price. Another possible anomaly could be the inclusion of affiliate sales at below-market prices. For DRA's failure to account for any such anomalies, PG&E et al. contend that DRA's use of the Alberta field direct prices provides no valid basis to infer market prices which were achievable by PG&E.

c. **Discussion**

In resolving parties' disputes over the valuation of PG&E's purchases of Alberta gas, we must clearly distinguish parties' different ways of defining the Alberta gas market. Parties ultimately agreed that the Province of Alberta was the appropriate geographical market in which PG&E could procure Canadian gas. PG&E/IPAC do not believe there is any one "Alberta gas market" whose price can be measured and applied indiscriminately to any end-user. Rather, they argue that each end-user constitutes a separate "Alberta" market whose prices are defined only by the alternatives available to that end-user.

DRA/SMUD/TURN, on the other hand, view the Alberta market as encompassing Alberta producer transactions to end-users outside of PG&E's service territory. PG&E's purchases of Alberta gas are thus treated by these intervenors as a mixture of PG&E's end-user alternatives outside of Canada as well as Alberta transactions outside of PG&E's service territory. DRA/SMUD/TURN all disagree among themselves as to the details over how much gas should be allocated an intra-Alberta price versus how much based upon non-Canadian end-user alternatives.

Accordingly, we first address whether gas sales originating within Alberta to end-users outside of PG&E's service territory have any relevance in determining PG&E's retail prices for Canadian gas. Then, to the extent such Alberta prices are relevant to PG&E's market, we must determine how PG&E's Canadian market prices would be affected.

With respect to the U.S. export market in general, we find no compelling evidence that Alberta spot gas prices were determined simply by either extreme of a single homogeneous intra-Alberta price or a price simply equal to end-user U.S. domestic alternatives.

PG&E's pricing model does not perfectly explain all the relevant factors determining Alberta spot gas prices. Nonetheless, PG&E was able to show that it offers a reasonable degree of validity that U.S. domestic supply alternatives played at least some role in Alberta exports of spot gas. However, PG&E has failed to show that Alberta spot gas prices were exclusively based upon the buyer's purchase alternatives outside of Canada.

PG&E's model raises issues concerning the degree to which Alberta producers exercised (1) price discrimination; (2) market dominance; and (3) restraint on competition among themselves.

(1) <u>Price Discrimination</u>

PG&E's pricing model points to some degree of systematic price discrimination by Alberta producers based upon each import buyer's U.S. market alternatives. To the extent price discrimination did occur, however, it was only partially successful and occurred within the context of various structural market imperfections. If sellers were able to price discriminate completely, we would expect to see a perfect correlation between the Alberta Spot Price variable and the TNV representing the buyer's supply alternatives. PG&E's model defines the parameter "Delta" as the coefficient measuring the extent to which the TNV (i.e., the transaction netback value of non-Alberta alternatives) correlates with the Alberta price. The model equation characterizing this price relationship is expressed as:

Alberta spot price = (Alpha) + (Delta)*(TNV) + (error term)

Under DRA's pricing hypothesis, the value of Delta would approach zero, producing a flat Alberta price curve (x axis) plotted against a range of TNV values (y axis). This is because DRA assumes that non-Alberta alternatives had no impact on the Alberta spot price. Under PG&E's hypothesis, by contrast, we would expect the value of Delta to approach 1.0, with the Alberta price tracking TNV. Yet upon review of PG&E's actual regression runs, we do not find that the Delta coefficient values closely approach either zero or one. PG&E performed six regressions (two sets of runs for each year 1988-90, one using interruptible and the other, firm transport rates). The resulting Delta values from the respective runs are summarized below:

Delta Values From PG&E Price Model

	Transport Assumptions		
Year	Interruptible	Firm	Combined Mean
1988	.508	.565	
1989	.679	.630	
1990	.492	.354	
Mean Value	.559	.516	.537

Thus, as measured by the Delta parameter, PG&E's study actually suggests that buyer alternatives account for only a portion of the price in U.S. export markets over time, ranging from a low of 35% to a high of 68%, depending on whether firm or interruptible transport is assumed. From this range of values, we can infer that Alberta spot gas exports varied considerably by geographic destination and did not converge towards a single price, as implied by DRA's disallowance assumption. By the same token, however, Alberta producers represented in the price model did not track precisely the full value of U.S domestic supplies. Alberta producers were only able to extract between 35% to 68% of buyers' alternative transaction netback value.

(2) Market Power

To the extent price discrimination did occur, however, it does not necessarily demonstrate market dominance. We find no basis to conclude that PG&E was completely at the mercy of either the A&S pool or of other Alberta producers to pay prices referenced merely to U.S. Southwest prices. Likewise, we are not convinced that PG&E had such market dominance to be able simply to demand the lowest price any Alberta producer might have realized on some isolated transaction in another market. PG&E's statistical measure of the relationship between the buyer's supply alternatives and Alberta producers' market price, i.e., its "Delta" value, does not indicate complete producer market power. Rather, it implies that in the U.S./Alberta spot import market generally, neither buyer nor seller possessed complete market power to extract all economic rents within any geographical sector studied.

Even to the extent there is a positive correlation between Alberta prices and netback alternative prices, it does not necessarily indicate an Alberta seller's ability to extract maximum economic rents. Such cases may simply reflect a depressed sales market where Canadian sellers are forced to be price takers, discounting their price even below prevailing netback levels available to other Canadian sellers in order to compete against cheaper domestic alternatives. Thus, it does not necessarily follow that Alberta producers could extract the full value of U.S. supply alternatives in robust sales markets, such as PG&E's. We do not believe that Alberta producers had unrestrained power to raise prices without regard for prevailing Alberta industry standards simply on the strength of expensive U.S. domestic prices. This belief is supported by the Delta values which indicate that on average, Alberta producers were able to extract only about half of the value of competing U.S. sources.

PG&E argues that its market power was limited by impediments which foreclosed access to Canadian gas except the A&S producer pool.

We conclude that Alberta producers as represented in PG&E's price model lacked complete market dominance and could not avoid all threat of competition from among fellow Alberta producers. Accordingly, we conclude that the potential existed for U.S. buyers to exert some market power and correspondingly to generate price competition among Alberta producers. The degree to which any particular U.S. buyer could stimulate such competition would depend on its bargaining strengths relative to prospective sellers of gas. We conclude as discussed in Section VI that PG&E had sufficient market power to invoke intra-Alberta price competition, at least for volumes in excess of 700 MMcf/d.

(3) <u>Competitiveness of the Alberta Market</u>

PG&E also differed with IPAC as to whether its price model provided evidence of the lack of competition among Alberta producers. To some degree, we find the disagreement between PG&E and IPAC as to whether the Alberta market was "competitive" to be one of semantics. Although IPAC alleges an internal inconsistency between PG&E's own witness Hogan and Ziff as to whether the Alberta market was competitive, we find no such inconsistency. Ziff did not dispute Hogan's testimony regarding price discrimination. He merely clarified that there are other aspects of market strategy, such as how producers choose to target sales, that influence market share. Alberta producers in general were aggressively competitive relative to U.S. producers. The evidence of price competition <u>among</u> Alberta producers is less obvious logically. We would expect for Alberta producers to offer gas to buyers at the highest price they could expect buyers to accept. From Alberta producers' perspective, this only represents good business practices in an attempt to achieve optimal investment returns (Exh. 1402, Tab 3, p. 14). By competing among each other, Alberta producers would only bid the price down, thereby reducing their profit. Accordingly, to the extent their market power gave them bargaining dominance to avoid competition, we would not expect Alberta producers to compete willingly among themselves. To the extent it shows a systematic pattern of price discrimination, PG&E's pricing model corroborates this expectation.

In contrast to the generic Alberta supply market, we conclude that by its intrinsic design the A&S pool voting mechanism foreclosed significant opportunities for price competition among members of the pool. The voting mechanism allowed the negotiation of only one price and made it applicable to all gas of the pool. Any intra-Alberta price competition would have to be between the A&S pool as a single unit and independent Alberta producers interested in serving PG&E customers. We discuss the producer voter mechanism in Section VII.

(4) Alberta Market Prices As A Proxy For PG&E's Purchases

The remaining question is to what extent the generic profile of the Alberta spot gas market as depicted by PG&E's price model has specific applicability to PG&E's consuming market prices. PG&E's market exhibited various characteristics which distinguish it from other typical U.S. buyers. PG&E was one of the largest single buyers of Alberta gas exports. Its relative proximity to the Alberta market resulted in relatively low transport costs. It paid prices which yielded producer netbacks among the highest in the industry.

As a result of these factors, PG&E represented a lucrative export market to Alberta producers. In fact, the California market was viewed as the most desirable Canadian export market in the U.S. (Exh. 1128, p. 2). The potential loss of such a lucrative market based upon high netbacks would logically make Alberta producers more vulnerable to buyer market power than would be true in a less lucrative market. PG&E/PGT's control of constrained capacity on the PGT pipeline as the sole conduit for such lucrative netbacks distinguished the PG&E market from other U.S. import markets, and indicates an additional source of buyer market power not necessarily available in other markets. While PG&E perhaps could not exercise full monopsonist powers over non-A&S producers, it certainly could offer significant weight in terms of its size as a single buyer. PGT's gas imports on behalf of PG&E represented the single largest gas import transaction which DOE oversees (IPAC Exh. 1402, Tab 4, p. 34).

As additional evidence indicating the ability of PG&E to extract a price below U.S. Southwest alternatives, we consider the manner in which PG&E conducted its negotiations with the A&S pool. Although PG&E highlights U.S. southwest prices as the standard for burner tip competition, A&S prices were not rigidly bound by this price standard alone. During each of the price renegotiations, PG&E thought intra-regional competition was significant enough to raise as a factor in its price offers. In 1990, PG&E explicitly referenced intra-Alberta gas prices as a benchmark for A&S pricing of certain volumes in its commodity rate analysis.

If A&S producers' market power and burner tip competition ruled out any prices below those in the U.S. southwest market, then it would have made no sense for PG&E even to attempt to suggest alternative benchmarks. Moreover, PG&E concedes that it was able to use the load factor benefits of core election as a bargaining chip in extracting an A&S price below the full cost of U.S. Southwest alternatives. Notwithstanding its claim of A&S market dominance, PG&E was in fact able to counteract A&S producers' attempts to price discriminate, at least to a small extent.

Thus, we conclude that PG&E had at least as much market power as the average buyer represented in PG&E's price model data. As such, the extent to which Alberta producers could discriminate with respect to short term sales to PG&E was about evenly matched with PG&E's power to bid the price down toward the low end of producers' opportunity cost. This conclusion is supported by the PG&E's pricing model which, on average, explains no more than about 50% of the Alberta market price by price discrimination. Consequently, PG&E's model supports an Alberta spot gas price not based simply upon U.S. Southwest alternatives, as PG&E claims. Rather, it supports a price which reflects a relative weighting of the mixed effects of both the buyer's and the seller's marginal opportunity cost associated with the transaction. We shall use this framework in deriving a market price which PG&E could have achieved, as discussed in Section VI.

We now turn our attention to the Alberta price proxy offered by DRA/SMUD/TURN. There are two general aspects of these parties' price assumptions which can best be discussed separately. One aspect is the proper measurement of an Alberta market price proxy applicable to PG&E's market. The other aspect is how an Alberta market price proxy should be weighted as a share of total PG&E purchases of Canadian gas.

With respect to the proper weighting of the Alberta market price as a percentage of PG&E's overall Canadian gas costs, DRA/TURN assume that the Alberta market proxy should be applied to the equivalent of 50% of PG&E's Canadian gas purchases while the remaining 50% volumes would be priced at recorded A&S levels. SMUD assumes that the remaining 50% of core purchases should be further reduced by Alberta one-year firm direct prices on a 50/50 basis with A&S recorded prices. We address the issue of the proper weighting of the Alberta market proxy in PG&E's market price determination in Section VI.

With respect to the proper measure of the Alberta market price proxy, there are several layers of dispute. First, assuming a generic Alberta market proxy were relevant to PG&E's market, should the proxy be based upon a spot price or a longer-term price such as a one-year firm direct price or some other measure? Assuming a spot price is the proper proxy for the Alberta market, should it be measured based upon the limited market for sales to end-users within Alberta (as assumed in DRA's spot price) or should it instead consider U.S./Alberta export spot sales prices which are higher? Even assuming a spot price limited to sales to end-users within Alberta were a correct proxy, PG&E/IPAC/CPA further dispute DRA's technical analysis underlying the specific price series it assumes.

We shall first address the reliability of DRA's technical analysis underlying its reliance on the price series which it characterizes as an intra-Alberta spot price.

We do not find that DRA adequately analyzed the Alberta field direct price as reported in the CNGF periodical to be a valid basis for the price of spot gas achievable by PG&E. The field direct prices cited by DRA represent one among several price series under various headings in CNGF gas price table (Exh. 1724, p. 15). DRA failed to explain why the field direct price was a better proxy than any of the other price series shown in the table. The only other price data which DRA referenced to cross check the field direct price data was from the publication "Natural Gas Week" and only for 1990 (Tr. 7158-60; Exh. 1408). For these reasons, PG&E/IPAC find DRA's spot price to be unsupported as a measure of prices in the Alberta market generally. DRA did not review or confirm the actual volume of gas sales reflected in the Alberta field direct price used as a basis for its disallowance calculation. (Exh. 1645; Tr. 7143-44.) Moreover, DRA's witness admitted under cross examination that "it's unlikely that they would be able to fill PG&E and PGT half full with gas at that field price, at the field direct price" (Tr. 7171).

DRA's price proxy measures transactions for only a fraction of the total Alberta gas market sales, limited to end-users located with Alberta. No foundation was laid to show that a price limited to the Alberta domestic market can be extrapolated to apply to 500 MMcf/d of gas sold to PG&E's market. DRA did no analysis of how a change in demand for spot gas might impact prices (Exh. 1648). PG&E presented data showing Alberta spot gas sales exported to the U.S. during the record periods was priced significantly higher than spot sales within Alberta. (See Section VI for further discussion.) The transmission cost for gas sold within the Province of Alberta is relatively low compared to the alternative of exporting gas to the U.S. (Tr. 8549). Thus, everything else being equal, Alberta producers would realize a higher profit for sales to local Alberta customers than to export customers such as PG&E. No rational producer seeking to maximize profits would sell gas to PG&E at the same price as to a local Alberta user and forgo the higher netback under such circumstances. Such producer would consider diverting the gas to A&S/PGT only at the price where the netback was equal to or greater than what was available in the domestic market. If Canadian gas producers could get a price higher than the next best market, even if lower than the A&S price, such producers would be induced to sell to PG&E. DRA did no analysis to show that the CNGF Alberta field direct price was the best that Alberta producers in the larger market could realistically achieve. On this basis, DRA's price proxy is flawed as a basis to assign a value to the equivalent of 50% of PG&E's Canadian gas purchases.

While we agree with IPAC's general observation that changes in demand can affect market prices, we are not persuaded that PG&E's prices would have risen by increasing its demand for spot gas. No party provides a quantitative assessment of either demand or supply elasticities associated with increased PG&E spot purchases. We would need to consider how supply volumes changed in response to an increased demand. Certainly, PG&E argues that A&S producers responded to the prospect of increased demand in the form of PG&E's core-elect market with a price decrease. Clearly, PG&E's increased demand had greater, not lesser, attractiveness to A&S producers. Likewise, other prospective Alberta suppliers may have found incremental PG&E demand to be attractive relative to other market options. Thus, such suppliers would have an incentive to increase gas production to meet PG&E's incremental demand as long as the price positively contributed to suppliers' return on investment. The interaction of <u>both</u> supply and demand changes must be considered to determine how the Alberta market price outside of the A&S pool would have responded to increased spot gas demand from PG&E.

Moreover, an offsetting problem would confront A&S producers. If PG&E refused a portion of their long-term supply, they would have to divert it to other markets, thereby increasing the supply relative to demand in other markets. Thus, we find IPAC's assertion inconclusive that increased PG&E demand, by itself, would have raised the market price for gas.

While we find that DRA has failed adequately to support the technical basis underlying its use of the field direct prices reported in CNGF to represent domestic Alberta spot prices, the record provides another source of domestic Alberta spot price data. PG&E develops its own independent data source for prices of Alberta domestic spot gas in Exhibit 1050 which essentially agree with the prices used by DRA, as shown below:

$/Dth

	1988	1989	1990
DRA prices (Exh. 1100)	$0.98	$1.08	$1.02
PG&E prices (Exh. 1050)	0.97	1.10	1.02

PG&E's spot price data series was developed by Ziff Energy Group and used by PG&E as the price variable "ABDPRICE" (the Alberta domestic spot price) in testing its spot price statistical model discussed previously. Since no party effectively challenged the validity of PG&E's "ABDPRICE" data series, we shall accept it as a starting point in determining a reasonable measure of Alberta spot prices paid by domestic end users within the Province of Alberta. To this extent, while we find DRA deficient in analyzing the basis behind the CNGF data, virtually the same essential Alberta domestic spot prices result based upon PG&E's analysis. The dispute still remains, however, as to the validity of using Alberta spot prices paid by end-users within Alberta as representative of prices which PG&E could realistically negotiate for spot gas purchases.

As we shall explain in the following section, while we reject the domestic intra-Alberta spot price as a valid proxy of what PG&E could pay for the equivalent of 500 MMcf/d of gas purchased on the spot market, we believe that the spot price for the Alberta export spot market does serve as a valid measure for the low-end floor of a bargaining range within which PG&E could have negotiated a market price for approximately 300 MMcf/d of short term gas purchases in Alberta.

VI. Adopted Disallowance of Imprudent Costs

None of the parties has offered a price proxy for Alberta gas which entirely reflects contemporaneous record period competitive forces. Accordingly, we must develop our own valuation of a market price for PG&E's purchase of Alberta gas volumes outside of the A&S pool.

Although the record in this proceeding is very extensive, it does not provide information to permit an exact determination of the best possible deal which PG&E could have negotiated. The give-and-take complexities of gas price negotiations do not lend themselves to a precise reconstruction of what terms would ultimately have been agreed upon. For purposes of testing the reasonableness of PG&E's costs, however, it is not necessary to identify a single best negotiating resolution. As we stated in D.90-09-088:

> "The reasonable and prudent act is not limited to the optimum act, but includes a spectrum of possible acts consistent with the utility system need, the interest of the ratepayers, and the requirement of governmental agencies of competent jurisdiction." (37 CPUC 2d 488, 499.)

Accordingly, we shall identify one pricing scenario whereby PG&E could have procured Alberta gas supplies by invoking intra-Alberta competition. Although this scenario is not the only reasonable one, nor necessarily the optimal one, it does fall within the spectrum of reasonable acts. It provides a proper basis for comparison with PG&E's recorded costs to assess whether a disallowance is warranted.

An initial issue in considering an alternative price proxy based upon the claims of DRA/TURN/SMUD is the appropriate starting point from which it should be computed. Both DRA and SMUD propose a disallowance for each month of the record periods based on lower prices beginning in February 1988. PG&E objects that even if a disallowance were to be imposed, the correct starting point from which to measure lower prices would be April 1, 1988, the date on which the 1988 price redetermination took effect. During February through March 1988, PG&E's prices and takes from the A&S pool were predicated upon the 1987 price redetermination which had previously been found reasonable by D.89-05-064. On this basis, PG&E argues that its Canadian costs should be found reasonable through March 31, 1988 on the basis that such costs were incurred pursuant to its 1987 purchase agreement with the A&S pool. We agree with PG&E that the appropriate starting point from which to measure any disallowance is April 1, 1988. This was the earliest point during the 1988 record period at which PG&E had the opportunity to renegotiate its purchase price and terms with the A&S pool. Prior to April 1, 1988, PG&E was purchasing gas pursuant to the 1987 purchase agreement whose price terms and quantities we had found reasonable in the previous year's reasonableness review. Accordingly, PG&E was bound by the terms of the 1987 price redetermination under which it took full volumes of A&S gas at 1987 contracted prices during February and March of 1988.

The only basis upon which we could include the months of February and March in our disallowance is if we assume retroactively that PG&E had negotiated different price terms and/or volume commitments with the A&S pool during the preceding spring of 1987. Not only would this require that we contradict our findings in D.89-05-064, but it would further require that we revisit in detail the reasonableness of PG&E's actions and available alternatives during the 1987 record period with respect to its A&S negotiations and supply alternatives. Even if it were appropriate to make such contradictory findings, the record in this proceeding did not cover the 1987 record period, except in general background as a context for evaluating PG&E's 1988-90 record period operations. Accordingly, we shall use April 1, 1988 as the beginning point for computing any disallowance.

Consistent with our discussion of PG&E's pricing model above, a pricing standard premised only on the buyer's alternatives presents one extreme side of a two-party negotiation. We believe this view portrays an unnecessarily passive picture of the bargaining leverage which PG&E could bring to bear based upon prospective Alberta producers' own alternatives. TURN's witness provided a useful hypothetical scenario illustrating PG&E's bargaining power relative to producers in extracting economic rents related to the PGT pipeline. During the cross-examination of witness Florio, the following exchange occurred:

> "Q. Would you agree...that in calculating the distribution of economic rents...that we have to consider the highest monopoly pricing scheme at the other end of the pipeline in California?
>
> "A. ...If PG&E controlled all the capacity and was a buyer in Canada in an unconstrained market, they could get a certain price. And if Canadian gas was selling in California in an unconstrained market, it could get a certain price... If PG&E had operated as a total monopsonist in Canada, they wouldn't have paid the Canadian market price; they would have paid each producer just the price that it took to keep that producer from shutting in their well...And...the market price is probably the highest shut-in price... So PG&E as a monopsonist could have done the flip side what you just posited the seller would do in the U.S." (Tr. 5137.)

While we recognize that PG&E did not buy in an unconstrained market and lacked the extreme market dominance painted in Mr. Florio's hypothetical, we likewise note that countervailing constraints would prevent Alberta producers from squeezing all economic rents out of PG&E. Yet, the theoretical extremes of total buyer/seller market power suggested in Florio's hypothetical illustrate a useful framework for defining the end points within which a bargaining range could exist.

From the seller's view, his goal would be to elicit a price aimed toward a high end point capped at PG&E's marginal alternative supply option. From PG&E's view, its goal would be to elicit a price aimed at a low end capped at the seller's marginal alternative opportunity cost. TURN's hypothetical assumed the low end was bounded just above well shut-in value.

Following through on this model, a market price can be derived by defining values for PG&E's buyer market alternative and Alberta producers' seller market alternatives.

To quantify the price of Alberta gas under this scenario, we must make findings concerning (1) a floor value representing the proxy of the Alberta producers' opportunity cost as an alternative of sales into the PG&E market; (2) a ceiling value representing the PG&E opportunity cost for purchase of gas as an alternative to independent Alberta producers; and (3) a relative percentage weighting representing the mix of these two price elements in the final negotiated price.

A. <u>Floor Value</u>

Our goal in identifying an appropriate floor value is to determine the marginal opportunity cost of Alberta producers with respect to incremental sales of short term gas to PG&E. As noted above by TURN, PG&E's goal assuming it had complete monopsonist market power would be to pay each producer just the price required to keep that producer from shutting in their well. This value would represent the theoretical opportunity cost of marginal short term sales to PG&E below which no sales would be economically feasible. Since PG&E did not possess complete monopsonist power, it would have to engage in give-and-take bargaining with producers for a price higher than this lower bound limit. But nonetheless, this lower bound still is relevant as a floor value toward which PG&E could bargain. We have already identified the domestic Alberta spot sales price as discussed above as a candidate for use as a floor price. As a further basis for our evaluation of a floor price, we shall consider other market data provided in the record concerning Alberta prices, as discussed herewith.

1. **Alberta Spot Gas Exports to U.S. Markets**

The Monthly Statistical Reports of the NEB provides data on Alberta spot prices for the Alberta export spot market which shows higher prices than DRA's intra-Alberta prices, but lower than A&S contract prices.

PG&E argues that recorded export prices should be further adjusted to reflect higher incremental transport costs which producers would incur to transport gas into PG&E's service territory. Since Alberta producers hold firm transportation rights primarily into the U.S. Midwest, they are obliged to pay monthly demand charges for transportation to U.S. Midwest pipelines whether or not gas is sold to that market. Thus, according to PG&E, to yield the same netback for a sale into California as into the Midwest, an Alberta producer would have to recover double demand charges, once for its sunk costs paid to U.S. Midwest pipelines and again for its actual transportation charges into California. Thus, PG&E further computes the NEB export spot gas prices required to yield the same netback to producers on sales into California as would be received on sales into the U.S. Midwest.

A comparison of spot gas prices computed on these different bases is summarized below. Column 1 shows intra-Alberta sales from Exhibit 1050 as a basis of comparison. Column 2 shows Alberta/U.S. export sales as recorded. Column 3 shows Alberta/U.S. export sales, as adjusted for double demand charges per PG&E's assumption. Column 4 shows recorded A&S prices for comparison.

Province of Alberta

Spot Gas Price Comparisons ($/MMBtu)

	(1) Intra-Alberta Spot Sales (per Exh. 1050)	(2) U.S. Export Spot Sales NEB (actual)	(3) U.S. Export Spot Sales NEB (adjusted)	(4) A&S Sales
1988	$ 0.97	$ 1.18	$ 2.00	$ 1.73
1989	1.10	1.14	1.95	1.82
1990	1.02	1.32	2.06	1.83

PG&E's theoretical adjustment to NEB export prices to reflect double demand charges assumes that gas otherwise destined for PG&E's market would have otherwise been sold into the U.S. Midwest market. Based upon our assessment of gas supply in Section V.D, we conclude that incremental sales to PG&E could have been made from surplus Alberta reserves without disturbing existing sales in other export markets. If such surplus reserves instead could have been sold profitably to the U.S. Midwest market during the record period, they would have been. Rather, it is evident that demand for Canadian gas into the U.S. Midwest market was already satisfied. Alberta producers had already recovered whatever pipeline demand charges they could through U.S. Midwest sales. Had Alberta producers attempted to sell more gas into that market, we believe they would have either found no additional demand, or else would have had to discount the price. Accordingly, PG&E's inflation of export prices to recover a double demand charge is not reflective of the market price which Alberta producers would have required from PG&E.

SMUD highlights comparisons between A&S export prices versus those paid by four U.S. Northwestern LDCs. In particular, SMUD cites the prices of Washington Water Power Company which purchased Alberta gas via PGT at an average border price of

$1.54/ MMBtu, or 68 cents less than PG&E was paying (Exh. 1200, p. 33). SMUD faults PG&E for not improving its leverage relative to Alberta producers to avail itself of comparably priced gas.

2. Other Producer/Aggregator Netbacks

PG&E's own assessment as presented in its 1989 application for approval of the PGT Expansion project (A.89-04-033) was that "current Alberta export netbacks" ranged from $1.20 to $1.80 per Mcf, and a calculated netback of $1.58 per Mcf was "in the range of current netbacks for Alberta producers" (Exh. 1300, p. 11), further indicating that the A&S prices were high relative to the Alberta market generally.

PG&E also cited revealing evidence in its 1990 commodity rate analysis to A&S producers concerning the disparity in A&S prices relative to the Alberta market at large:

> "In 1989, the average Alberta field-gate prices paid by major aggregators, excluding A&S supplies ranged from $1.20 to $1.40 per MMBtu. One year firm direct purchase prices ranged from $1.1 to $1.32 per MMBtu. The commodity price of long-term exports, excluding A&S supplies, were between $1.30 and $1.72 per MMBtu, with an average of $1.48 per MMBtu. An intra-regional price comparison suggested that in 1989, the Alberta market price would be approximately $1.99 (summer months) to $1.49 (winter months) per MMBtu for short-term sales. (Ex. 1024, p. 9)

3. Alberta Exports to Eastern Canada

PG&E argues that A&S prices were in line with prices paid by eastern Canadian LDCs for Alberta gas exports. According to PG&E, eastern Canadian LDCs faced similar provincial regulatory controls, pipeline capacity constraints, service obligations, and competitive markets. Field gate price data for 1988-90 purchases by major Eastern Canadian LDCs and their historical supplier, Western Gas Marketing Limited (WGML), are compared to A&S prices below:

	1988	1989	1990
Eastern Canadian LDCs	$1.96*	$1.83**	$1.82***
A&S	$1.73	$1.82	$1.83

* Covered period 11/1/86 - 10/31/88
** Covered period 11/1/88 - 10/31/90
*** Covered period beginning 11/1/90

PG&E also concedes that A&S prices were in fact higher than prevailing Alberta prices available in eastern Canadian markets generally. For example, in its opening brief, PG&E states that Alberta sales to Eastern Canada were in fact made "at prices significantly below the A&S price." (Opening Brief, p. 155.)

4. **The Alberta Average Market Price (AMP)**

Another market indicator is the "Alberta Average Market Price" (AMP) which is a monthly price index developed by the APMC and used in determining Crown royalty payments (Tr. 8062; 8578-79). The minimum acceptable Crown royalty payments are based upon a floor price of 80% of the AMP. The AMP represents a wide cross section of gas sales from Alberta, computed on a three-month moving average basis (Tr. 8579:3-5/Ziff). PG&E considered the AMP to be a sufficiently representative benchmark of competitive prices to use it in developing its initial 1990 A&S price offer for volumes above 700 MMcf/d. The average annual values for the AMP and the floor price for royalty payments computed by the APMC (equal to 80% of the AMP) were as follows during the record periods:

($/Dth)

	1988	1989	1990
AMP	$1.33	$1.36	$1.40
APMC Floor Price For Royalty Payments	1.06	1.09	1.12

5. **Discussion**

We conclude that the Alberta spot price for the export market as compiled by the NEB constitutes a reasonable proxy of the floor value applicable to Alberta producers. This is the lowest market price on the record at which sales transactions into the United States actually occurred. Thus, Alberta producers logically would only consummate such transactions if they resulted in a positive marginal revenue contribution.

An alternative proxy that we seriously considered using, but ultimately rejected, was the domestic Alberta spot price as measured by PG&E in Exhibit 1050. Unfortunately, many of the same problems that we found applicable to DRA's Alberta gas field direct price are equally applicable to PG&E's domestic Alberta spot price. These problems include the argument that domestic Alberta spot sales constituted only a small fraction of the total Alberta market, and that there may be a downward bias in the data due to distributional bottlenecks and constrained gathering receipt points which limited the ability of Alberta producers to sell gas. While we have previously concluded that ample supplies of spot gas would have been available had PG&E chosen to utilize these supplies as part of its procurement strategy, we are uncertain that the intra-Alberta spot price would have been the appropriate floor price for PG&E in bargaining for these supplies.

Accordingly, we will utilize the NEB Alberta spot price as the appropriate floor price. Based on the record before us, this price appears to be the most representative of available gas supplies that were adequately connected into the gas pipeline systems of Alberta for export to the United States. Thus the true shut-in price applicable to Alberta producers willing to export gas to the United States was less than or equal to the NEB export spot price.

We recognize that the record developed in this case does not permit precise measurement of the appropriate shut-in value.

We adopt the NEB Alberta export spot price as the most suitable proxy available from the record, but remain open in subsequent reasonableness reviews to the consideration of more accurate measures of the true shut-in price in evaluating PG&E's bargaining performance.

We will also reject the use of the AMP as an appropriate measure of the applicable floor price for short term gas prices. We are seeking a measure of short term gas prices, the AMP represents predominantly long term gas prices. This is true since the AMP measures a cross section of all Alberta sales which are overwhelmingly dominated by long term contract gas sales.

Even though we will not use the AMP or the U.S. export price as measures of a floor price, these price values still illustrate the extent to which the A&S price commanded a significant premium over the prices which other Alberta market producers and aggregators were able to realize. The AMP also serves as a useful check against the reasonableness of the prices that we determine PG&E could have negotiated for its incremental load. For purposes of comparison, we summarize in Appendix E how the A&S price compares with other measures of Alberta market prices discussed above.

B. Ceiling Value for PG&E's Market Alternatives to Independent Producers

For purposes of our pricing calculation, we must determine a value for the high end of the bargaining range between PG&E and independent producers. Logically, PG&E's next best alternative to independent Alberta producers would be the A&S pool, itself. If independent producers bid anything above A&S prices, PG&E could instead purchase from the A&S pool. Thus, we shall use the A&S price as the high end of the bargaining range applicable to independent Alberta producers in our pricing assumptions.

C. Volumes PG&E Could Have Bought From Independent Producers

Another critical assumption in our pricing calculation is the amount of gas which PG&E could have purchased outside of the A&S pool assuming a competitive price could be agreed upon. We have considered above the various arguments presented by PG&E and others as to why it was allegedly unable to substitute short-term Alberta gas volumes for long-term gas from the A&S pool. Our purpose here is to weigh in summary fashion all the various arguments to determine how much short-term gas PG&E could have realistically purchased to displace A&S producer pool volumes.

All parties agree that contract volumes were properly taken from the A&S producer pool at least up to the minimum 50% take level. DRA argues that volumes above the 50% take, representing as much as 500 MMcf/d of A&S supplies, could have been displaced with short-term purchases from other Canadian sources. PG&E/IPAC/CPA argue that various constraints precluded any displacement.

We conclude that PG&E could have ultimately extracted an agreement for reduced volumes from the A&S pool averaging 700 MMcf/d. This assumes a reduced price based upon alternative Alberta supplies could not be negotiated with the A&S pool for volumes above this level. As concluded in Section V.B., it was reasonable for PG&E to take more than the 50% minimum contractual requirement--at least up to 600 MMcf/d during the record periods--to avoid incurring costs related to prior TOP obligations of PGT. In addition to the PGT TOP liability, A&S incurred its own additional TOP obligations with the A&S producer pool. Although A&S required minimum takes of at least 700 MMcf/d to make up its TOP liability, we do not recognize the A&S upstream TOP obligations as a responsbility of PG&E's ratepayers, as explained in Section V.B. Accordingly, the 700 MMcf/d requirement to satisfy A&S TOP obligations has no bearing on our determination of the volumes PG&E had to purchase from the A&S pool.

Yet, apart from the A&S gas volumes required to satisfy TOP obligations, we conclude that it was reasonable for PG&E to take an average of 700 MMcf/d from the A&S pool in order to assure core demand could be met reliably, as explained in Section V.D.5.

While PG&E could have invoked intra-Alberta competition based on a credible threat of bypassing the A&S pool for volumes in excess of 700 MMcf/d, it could not invoke the same threat for remainder of its A&S purchases. If limited to reduced A&S volumes of 700 MMcf/d, we doubt A&S producers would have accepted a lower price knowing that PG&E had no credibly cheaper alternative. On the other hand, A&S producers would have been significantly constrained from demanding a higher price in retaliation for reduced takes. We discuss the pricing impacts of reduced takes of A&S pool purchases further in Section VI.E.

We believe that 700 MMcf/d on average throughout the record periods would represent a reasonable threshold offer to the A&S pool. Given the lucrative netbacks offered by PG&E, we are unconvinced that the A&S pool could have easily found a better offer elsewhere. Faced with the alternative of losing all of the core elect load, the A&S pool would have had an incentive to accept PG&E's offer. Given that PG&E was already close to the ceiling cost of alternatives based upon full A&S takes, the A&S pool would have had limited flexibility to threaten to raise the price further in retaliation for reduced takes without violating the competitive pricing provision of the International Contract.

In summary, a reasonable overall assumption as to the maximum amount of gas PG&E should have taken from the A&S pool if the pool refused to offer a price competitive with alternatives within Alberta is 700 MMcf/d. As concluded in Section VII, we believe A&S producers would have recognized that it was in their interests to deal with PG&E and meet its competitive alternatives rather than to seek alternative sources at perhaps less favorable terms. Yet, for purposes of our analysis, we assume the pool did not deal with PG&E for volumes over 700 MMcf/d in order to show that PG&E could have procured cheaper Alberta alternatives and was not powerless to resist A&S producers' demands for higher prices.

PG&E would have essentially been confronted with two sets of Canadian purchase arrangements: (1) purchase of the equivalent of 700 MMcf/d of long-term supplies through the A&S producer pool and (2) purchase of remaining Canadian gas needs through separate negotiations with independent Alberta gas producers.

D. Market Price Applicable to <u>Incremental Volumes Above 700 MMcf/d</u>

Having established a high-end and low-end benchmark for bargaining with Alberta producers for incremental volumes above 700 MMcf/d, we must consider how such price data could reasonably influence PG&E's market-specific prices for Alberta gas outside of the A&S pool. This depends on how successful PG&E could have been in stimulating competition among Alberta producers to drive the price toward the AMP level. At the same time, we must consider how successful Alberta producers would have been in driving the price upward to PG&E's next best alternative. Whether PG&E negotiated with the A&S producer pool or other independent suppliers for gas priced based upon competitive alternatives within Alberta, the final price would have depended on the relative bargaining leverage and skill on both sides.

DRA and TURN propose a 50/50 weighting of Alberta spot prices and the A&S price in deriving an average PG&E price for Canadian gas. Yet, they propose to apply the 50/50 ratio to the full A&S volumes. A 50/50 sharing applied to total A&S volumes is overly optimistic in terms of the results PG&E could have achieved. We agree with the general concept of a sharing of rents, but we find no basis to apply this sharing on a 50/50 basis to the equivalent of all A&S volumes. This result would be equivalent to paying 100% of the A&S price for 50% of A&S volumes and an average Alberta spot price for the remaining 50% of the volumes. We find it more realistic to view the sharing of rents in terms of PG&E's relative market power. Logically, PG&E possessed more market power with respect to incremental supplies which it could credibly seek to procure outside of the A&S pool. We believe the sharing of rents for incremental volumes which PG&E could procure outside of the pool would be different than sharing of rents for volumes for which it was obligated to purchase from the A&S pool.

Thus, for incremental volumes above 700 MMcf/d, a weighting of 50/50 between the buyer's alternatives (i.e., A&S price) and the seller's alternatives (i.e., the Alberta export spot price) represents a reasonable proxy of how a PG&E-market specific price could have been negotiated with Alberta producers. We find that DRA/TURN's concept of an economic sharing of rents supports the use of a 50/50 weighting when applied to incremental volumes.

We find further support for a 50/50 weighting of incremental volumes in PG&E's price model results. Although we recognize the limitations in PG&E's price model, it provides a statistical quantification of the extent to which Alberta spot market prices in general incorporated the influence of buyer market alternatives. As discussed previously, we conclude that PG&E's ability to buy gas in alternative markets would reasonably play some role in the negotiation of a final price with independent Alberta producers, consistent with PG&E's pricing model. The model derives a "Delta" value which measures the extent to which the Alberta market price is correlated with an end-user's buyer market alternatives.

Although we recognize that the relative balance of supply and demand varied in each year of the record period, we are not convinced that the PG&E model is precise enough to distinguish these year-by-year variations. We shall therefore use a common average for each of the three years of the record period. Over the three year period, the Delta values average about 50% of the Alberta price. In other words, about 50% of the modeling of the Alberta spot market price is accounted for by the buyer's specific market alternatives. PG&E's market size gave it relatively more market power than a typical U.S buyer. It is consistent with the results of the model to apply its Delta value only to purchases of incremental spot gas, not to total long-term A&S contract purchases. This is because the model tested only the prices in the spot gas market.

Given the range of variation in the Delta values, we conclude that a 50% weighting is reasonable and even conservative, in light of PG&E's relatively greater power as a single large buyer. We thus apply a 50/50 weighting of the floor and ceiling values derived above to volumes in excess of 700 MMcf/d. Accordingly, we conclude that PG&E could have negotiated a price with independent Alberta producers for residual volumes over 700 MMcf/d which reflected a weighting based on 50% of the price of its alternative supplies and 50% of the producers' alternative floor value, as represented by the Alberta export spot price for each year of the record period.

Our resulting price value for supplies in excess of 700 MMcf/d from independent Alberta producers can be derived for each year of the record period as follows:

Derivation of PG&E Market Price for Incremental Volumes
($/Dth)

50%*	A&S price	+	50%*	Alberta Spot Price	=	PG&E Mkt Price
50%*	1.72	+	50%*	1.18	=	$1.45
50%*	1.81	+	50%*	1.14	=	$1.48
50%*	1.83	+	50%*	1.32	=	$1.57

E. Market Price for Purchases from A&S Pool for Long-Term Volumes Up to 700 MMcf/d

In Section VII, we address the issue of what prices could have reasonably been negotiated between PG&E and A&S producers assuming the full PGT capacity was assigned to purchase of long-term gas from the A&S pool. Here, we are interested in what prices could reasonably have been negotiated had PG&E purchased only an average of 700 MMcf/d from the A&S pool with the balance from independent suppliers, as outlined above.

In its disallowance calculation, DRA assumes that if PG&E had displaced up to 50% of its A&S volumes with spot gas, it would have been reasonable for it to purchase from the A&S pool the remaining 50% of volumes at unit prices equal to what it actually paid to the A&S pool. SMUD goes even further than DRA and assumes PG&E not only could have reduced its A&S takes, but could have further reduced the contract price for the remaining long-term A&S pool purchases based on a 50/50 sharing of rents. TURN does not address what sharing of rents would be appropriate on a reduced take from the A&S pool.

PG&E/IPAC/CPA, on the other hand, argue that had A&S pool takes been reduced to 50%, the A&S producers would no longer have had an incentive to restrain their price offer in exchange for the load factor benefits of serving the core-elect market. Thus, A&S producers would have bid up the price for remaining takes to the

U.S. Southwest price, thereby costing core ratepayers more, not less.

PG&E's argument assumes that the A&S pool accepted a price below the expected equivalent U.S. Southwest price during each annual price redetermination and did so in exchange for a more favorable load factor. Assuming such a price discount existed, the A&S pool could have threatened to bid up the price on its reduced sales volume to equivalent Southwest levels in retaliation for PG&E reduced load committed to the A&S pool. In theory, we agree that A&S purchases at a high load factor represented greater economic value to the A&S pool than at a lower load factor. The question is whether PG&E in fact extracted price concessions from the A&S pool in exchange for the higher core elect load factor. Second, assuming there was some discount, how elastic was the price in relation to changes in expected load factor? The A&S pool could not bid up its asking price in retaliation for lost load factor unless it had initially discounted its price below PG&E's available alternatives. Third, could the A&S pool raise its prices and still be competitive not only with alternative Southwest supplies but also with alternative fuels such as fuel oil.

As previously discussed in Section V.C.3, hindsight measures of claimed A&S price savings do not inform us as to the expected price comparisons during each price redetermination period. The negotiating parties' expectations of prospective Southwest price alternatives during each price redetermination can best be gleaned by reference to PG&E's annual commodity rate analyses of competing prices. In its comments to the Proposed ALJ Decision, PG&E argues that to match its marginal supply alternatives, A&S producers could have demanded a price as high as $2.60, $2.28, and $2.20 per MMBtu during each annual price redetermination for 1988, 1989, and 1990, respectively. We find these prices unrealistically high in light of PG&E's own commodity rate analyses used in each annual price redetermination, as discussed below. Based upon the comparisons presented in PG&E's contemporaneous commodity rate analyses, no competitive discount was negotiated for A&S prices relative to Southwest prices.

PG&E's claimed $2.60 benchmark price for 1988 is based upon a statement made in a consultant study produced by a consulting firm, Recon Research, which stated that "...the Canadian commodity rate could be as high as $2.60 and still compete with oil." (Exh. 1753, p.2.) Yet, PG&E's own 1988 commodity rate analysis showed that the equivalent fuel oil cost was only $1.44/MMBtu. (Exh. 1022, Attach. 9). Moreover, PG&E's 1988 average commodity rate analysis shows that the equivalent netback values for competing non-Canadian alternative gas supplies were in the range of $1.50 to $1.99 at a 70% load factor. If we limit the comparison to Southwest sources, the equivalent average price is $1.78 (average of $1.99 El Paso and $1.57 short-term gas). (Exhibit 1022, p. 45). Even this rate is below the $1.83 PGT mean commodity rate.

PG&E's claimed $2.28 equivalent price for 1989 represents the upper end of the range of alternative equivalent prices in its 1989 commodity rate analysis. PG&E's 1989 commodity rate analysis actually showed a range of $1.12 to $2.28. Yet, aside from the fact that PG&E uses the extreme upper end rather than the midpoint of the range, PG&E admitted in the 1989 rate analysis that the range is unreliable "due to different fixed cost recovery mechanisms on the PGT and El Paso systems. Therefore, PG&E assigns little weight to these figures when evaluating the PGT-Canadian commodity rate." (Exh. 1023, p. 65.) PG&E also noted that the range narrowed to $1.64 to $2.01 when greater emphasis is placed on average cost sequencing and competition from other preferred core portfolio gas suppliers..." (Exh. 1023, p. 63.) Given PG&E's own discounting of the $2.28 rate during 1989 negotiations, we find little credibility in PG&E's current reliance on this rate as a fair proxy of even the high end of PG&E's competing alternatives.

If we limit the comparison only to the 1989 projected long-term Southwest alternatives, the commodity rate analysis shows an equivalent rate of $1.91. (Exh. 1023, p. 71.) This rate exactly equaled the 1989 PGT weighted commodity rate. Again, in 1989, there was no A&S price discount below alternatives.

In support of its claim that the equivalent alternative price for 1990 was $2.20, PG&E cites a June 1990 Canadian newspaper article reporting that Shell Canada believed "Canadian producers should be paid 25 to 35 cents <u>more</u> for each Mcf of gas shipped." (Exh. 1008, p. 3-49.) A price of $2.20 would be 30 cents above the A&S Tier I price of $1.90 which was negotiated in 1990. Yet, again, the opinion expressed in a Canadian newspaper article is at odds with PG&E's own 1990 commodity rate analysis. Based upon PG&E's own analysis the threshold price for preferential sequencing was in the range of $1.55 to $1.90. (Exh. 1024, p. 85.) On this basis, the 1990 PGT California border commodity rate of $1.99 did not reflect any discount relative to Southwest alternatives of $1.85. (Exh. 1024, p. 89.)

PG&E's commodity rate analyses amply demonstrate that the A&S pool had no bargaining latitude to increase its unit price without becoming uncompetitive even with Southwest sources. Commodity rate comparisons are particularly sensitive to load factor assumptions given the effects of fixed cost allocations on volumetric rates. PG&E argues that the low (70-75%) PGT load factors assumed in these comparisons helped to steer the negotiations in favor of PG&E's ratepayers (Tr.8012-8013).

However, under our adopted prudent procurement alternative, the A&S producer pool's effective load factor on PGT would have been about 70% (700 MMcf/d), even though the PGT pipeline would still have operated at full load factor.

Also the seasonal timing of purchases on the El Paso relative to PGT pipeline would impact the relative commodity cost comparisons. Since PG&E base-loaded Canadian gas purchases, Southwest gas was purchased disproportionately during the winter period when prices tended to be the highest. When Southwest prices were relatively low, Southwest gas would not displace A&S gas unless the price differential exceeded 20 cents/Dth, as explained in Section V.G.1. PG&E's preferential purchase of Canadian gas relative to Southwest biased any comparison of actual average prices.

To further confirm that the A&S pool lacked bargaining latitude to raise prices in retaliation to a reduced PGT sales, we can derive an equivalent Canadian commodity rate consistent with the alternative purchase scenario we outline in Section VI.C. This calculation is outlined in Appendix F. Under this scenario, instead of the normalized load factor applied to both the El Paso and PGT pipelines, we assume that PG&E offered the A&S pool only 700 MMcf/d. Thus, as noted above, while the PGT pipeline would remain at full load factor, the A&S pool's market share would only represent about a 70% load factor (see line 3). Likewise, the El Paso pipeline would be expected to remain at or near full capacity. We have used actual load factors as a proxy for expected demand on the El Paso pipeline. Using these revised load factors, as shown on lines 2 and 3 of Appendix F, we compute the expected Southwest delivered cost and the equivalent Canadian Commodity cost at lines 9 and 10.

We derive this calculation by computing the ratio of load factors used in the commodity rate analysis relative to our assumed 700 MMcf/d purchase scenario. We then apply this ratio to the fixed costs of Southwest and Canadian gas sources, respectively. As a result, we derive equivalent commodity rate comparisons, as shown in Appendix F, and summarized below in $/Dth.

(1) Year	(2) Actual PGT* Commodity Rate	(3) Equivalent Canadian Commodity Rate**	(4) Comparison: Actual versus Equivalent Rate (4) = (3)-(2)
1988	$1.83	$1.80	-0.03
1989	1.91	1.91	-0.00
1990	1.99	1.88	-0.11

* Source: Exh. 1010, p. 4,5; Appendix F, Line 11
** Source: Appendix F, Line 10

This comparison of commodity rates confirms that A&S prices negotiated by PG&E reflect no discount. In fact, under the assumptions used in Appendix F, the A&S price is above the equivalent alternative rate. To illustrate, Appendix F shows that for 1989, the expected delivered cost of Southwest gas at the California border was $2.41/Dth ($2.20 for the commodity itself plus $0.21 for transportation to the border). The key step in PG&E's commodity rate analysis was to determinew the maximum competitive Canadian commodity rate at which -- when Canadian/PGT transportation costs were added in -- the total cost of Canadian gas was just competitive with the total cost of Southwest gas (i.e. competitive on an average cost basis, per Commission guidelines). Since Canadian/PGT Canadian costs are $0.50 at a 70% load factor (Appendix F, Line 7), the maximum competitive Canadian commodity rate (at the California border) is $2.41 minus $0.50, or $1.91. But the 1989 negotiations produced a Canadian commodity rate (at the California border) of $1.91. And for 1988 and 1990, the competitive Canadian commodity rate is actually well below the actual PGT commodity rate (Appendix F, Lines 10-12). Accordingly, there was no significant ability of the A&S pool further to bid up the price above levels actually paid in retaliation for reduced takes without becoming uncompetitive.

Another significant limit on the ability of A&S producers to raise gas prices in retaliation for reduced loads was the price cap on gas that alternative fuels such as fuel oil imposed. Had the A&S producers sought to increase prices too far, they risked becoming uncompetitive with fuel oil and thereby losing a significant portion of their core elect load. As PG&E itself noted in its 1990 commodity rate analysis:

> Alternate fuel prices generally set a competitive "ceiling" on gas prices at the burner tip, assuming that customers fully reflect the total gas transport cost when making interfuel purchase decisions.(Exhibit 1024, p. 84)

PG&E's own calculations of A&S prices relative to fuel oil prices for each of the three years under review reveal that any attempt of A&S producers to raise prices 1988, 1989, and 1990 risked making A&S purchases uncompetitive. For example, PG&E's 1988 analysis noted that the forecasted fuel oil price of $16.74 per barrel equals a Canadian netback price of $1.80 (Exhibit 1022, p. 52) and that by 1990 fuel oil prices had fallen to the A&S equivalent of $1.20 to $1.60/dth (Exhibit 1024, p. 84). PG&E's bargaining position with A&S producers for each of the three years also noted that fuel oil and alternate fuel prices served as effective caps on the ability of A&S producers to raise prices (<u>See</u> Exhibit 1022, p. 41-42; Exhibit 1023, p. 65-66; Exhibit 1023, p. 83-84). TURN, in its testimony (Exhibit 1300, p. 10) also cites the 1989 proposal letter of John Sproul, PG&E Executive Vice President to the A&S producers where he notes that:

> The new price reflects PG&E's analysis of competitive conditions based on gas-to-gas competition as tempered by lower oil prices.

It was also during this time that PG&E was offering discounts off of its transportation rates for some customers in order to keep them from switching to alternate fuels. Therefore, given the large size and volume of PG&E's electric load as a percent of PG&E's core-elect load it is unclear how A&S producers could have remained competitive had they attempted to raise prices above the actually negotiated levels.

Contrary to the assumptions of DRA/SMUD/TURN, we doubt PG&E could have significantly bargained with the A&S pool for a lower unit price if PG&E were to reduce its takes only to 700 MMcf/d (let alone 500 MMcf/d). PGT/PG&E's ability to bargain for a lower A&S price based upon cheaper Alberta market comparisons depends significantly on PG&E's power to seek Alberta alternatives outside of the A&S pool without overall detriment to its customers. We do not believe PG&E had a realistic alternative within Alberta for supplies up to 700 MMcf/d. Had PG&E sought to reduce its A&S pool takes below 600 MMcf/d, it would have triggered TOP penalties, potentially eroding any savings otherwise achievable. Thus, we conclude that pricing at PG&E's actually negotiated price for these reduced volumes of 700 MMcf/d reasonably represents PG&E's competitive price alternatives.

F. Quantification of Imprudent Costs

We compute a disallowance based on the net savings which PG&E could reasonably have achieved by purchasing gas for its requirements in excess of 700 MMcf/d at the prices we develop above. We recognize, as noted previously, that there is a range of different outcomes within which we would consider PG&E to be prudent. The scenario we develop is only one possible outcome.

In deriving a disallowance, we use the price assumptions developed above. Our calculation of achievable net savings result from lower prices paid on incremental volumes of about 300 MMcf/d based upon a 50/50 weighting of the A&S ceiling price and the

Alberta spot gas floor price, less the higher prices on 700 MMcf/d as discussed above.

Our computation represents a mid-range outcome among the alternatives which reasonably could have been achieved in structuring a price offer to Alberta producers based upon the competing alternatives. PG&E's Canadian purchases under our computation may be summarized as follows:

For volumes up to 700 MMcf/d:	Purchased under long-term contracts from A&S Producer Pool, at actual negotiated prices.
For volumes over 700 MMcf/d:	Purchased from independent Alberta producers priced at the PG&E market price derived in Appendix B.

A full derivation of the resulting cost savings is presented in Appendix B. Applying accrued balancing account interest of $25,430,000 to the above calculation through December 1993, we compute a disallowance in the amount of $115,563,000. We find that this disallowance, based upon the achievable savings computed in Appendix B, is a reasonable estimate of the higher costs directly resulting from PG&E's imprudent action.

VII. Reasonableness of PG&E's <u>Negotiations with A&S Producers</u>

A. <u>Positions of Parties</u>

In this section, we address the reasonableness of the prices paid for A&S gas assuming full volumes were taken from the A&S pool.

PG&E praises its efforts in negotiating with A&S producers as being very aggressive, noting that the A&S prices were significantly lower than its less reliable Southwest supplies. PG&E computes that it paid $170 million less for its Canadian supply compared with Southwest sources on an average cost basis, and $307 million less on an incremental cost basis. PG&E's proposed offers and responses of A&S producers and Canadian officials are summarized at Figure III-4 of PG&E's opening brief.

DRA contends that as an alternative to purchasing incremental volumes outside of the A&S pool, PG&E could have bargained more aggressively for lower prices based upon intra-Alberta competition. TURN views this as the primary means by which PG&E could have achieved lower prices. DRA and TURN agree that a sharing of economic rents on a 50/50 basis between PG&E and the A&S pool would have provided a reasonable overall A&S price. The disallowance proposed by DRA is the same irrespective of whether PG&E were to have simply bargained more aggressively with the A&S pool or were to have purchased incremental volumes elsewhere. Even if PG&E did not displace A&S contract volumes with spot gas, DRA and TURN still believe PG&E could have used the threat of such action as bargaining leverage to induce the A&S producers to accept a lower price, based upon other market prices within Canada. SMUD does not believe full A&S volumes should have been taken under any circumstances, but still contends that PG&E and A&S could have achieved a 50/50 sharing of rents for reduced core volumes.

Thus, DRA asserts that its disallowance of $390 million reflects a conservative estimate of the amount of savings which could have been realized through better bargaining. DRA believes that PG&E guaranteed the highest price it could justify to Canadian producers while at the same time ensuring that its affiliate's supplies would retain sequencing priority over Southwest gas supplies. DRA faults PG&E's negotiated price for being 75% over the Canadian spot price.

While TURN offers no opinion on the reasonableness of gas prices prior to the 1989 price redetermination, it concludes that PG&E acted unreasonably in its 1989 and 1990 price redeterminations in failing to negotiate a lower price with Alberta producers. TURN asserts that there were substantial economic rents associated with access to the PGT pipeline during 1988-90 attributable to the disparity between Alberta and California market prices and the scarcity of low-cost pipeline capacity. Although A&S producers captured 90% or more of those rents, according to TURN, a "more equitable and defensible outcome" would have been for producers and consumers to have shared the economic rents equally. TURN does not offer a specific quantification of the correct Alberta market price or the resulting disallowance it would propose.

TURN joins DRA and SMUD in arguing that PG&E should have pursued open access status for the PGT pipeline and converted a portion of its firm sales rights to firm transportation. For TURN, however, this move would have been used principally to strengthen PG&E's bargaining leverage in negotiations. A realistic threat of displacement by alternative suppliers would have placed PG&E in a stronger bargaining position.

TURN acknowledges that it supported core election for PG&E's UEG as early as November 1988, but its support was conditional. TURN viewed core election as a bargaining chip whose value depended on how aggressively PG&E used it to extract a low price in A&S producer negotiations. TURN asserts that PG&E made no effort whatsoever to obtain the benefits of lower Canadian gas prices for its customers and in fact acted more as a marketing agent for A&S in proposing $1.90 per MMBtu, the highest price that could be obtained without loss of market share for A&S producers. TURN believes that PG&E could have reasonably negotiated a price that yielded a 50/50 sharing of PGT economic rents (measured by the difference between California and Alberta market prices).

In order to find that PG&E could have negotiated more aggressively to sustain lower prices, we must find that PG&E had sufficient buyer market power to overcome any resistance of the A&S producers, as well as the Canadian government interests, to such a reduction in price.

B. <u>Overview of the Annual Price Redetermination Process</u>

As a basis to evaluate PG&E's negotiations with A&S producers, we first review the negotiation process. The primary vehicle to establish the price of A&S long-term gas supplies was the "annual price redetermination." This process evolved out of the Canadian government's deregulation of gas price controls beginning in 1984. By this time, competitive market forces within the U.S. were increasingly eroding the market share of Canadian suppliers' whose prices were then set by Government mandate. The Canadian government began to revise its regulated pricing structure to permit Canadian gas prices to become more competitive with alternate sources within the U.S.

Effective November 1, 1985, Canadian gas exporters were given the option either (1) to negotiate market-based prices at the Canadian border on a one-on-one basis for each contract or (2) to follow a netback pricing arrangement, based upon system producers selling to a single aggregator based on a single price. In 1986, A&S decided to retain netback pricing provisions in its contracts with Alberta producers since this would require the producers to meet competition in PG&E's end-use market.

Alberta's Natural Gas Marketing Act became law October 30, 1986. Part 2, Section 9 of the Act prohibits the removal from Alberta of "net back gas...unless there is in effect...a finding of producer support in relation to that netback gas..." The Act also provided for arbitration of prices where buyer and seller could not reach agreement. Such arbitration, however, was to take into account the gas price in the respective end-use market. PG&E thus asserts that during the record periods, A&S was left with only two alternatives: Either (1) to accept netback pricing with its producers and comply with the producer approval mechanism established by the NGMA or (2) attempt one-on-one negotiations with each producer, subject to the risk of arbitration based on the same end-use market price criterion.

The contract price which A&S paid to the producer pool was subject to approval of the APMC based upon its finding of "producer support". Under the NGMA, producer support is determined through a balloting system whereby each producer either approves or disapproves the shipper's proposed price. A finding by the APMC of producer support required 60% producer ballot approval by sales volume.

PG&E's gas purchasing strategy at the beginning of the 1988 record period was based upon its gas purchase policy effective April 1, 1987. PG&E's revised purchase policy was aimed at encouraging suppliers to establish one-year fixed prices to qualify as long-term supplies for the core portfolio as defined by our industry restructuring directives. Accordingly, A&S producers agreed to fix their prices for one year to qualify as a long-term core supply.

As a basis for negotiations, each year, PG&E prepared a commodity rate analysis setting forth its evidence on pricing, along with a transmittal letter to PGT and A&S describing the price offer. A&S, in turn, submitted this material as its offer, along with a ballot, to each producer for its acceptance or rejection pursuant to the NGMA voting mechanism. As part of the negotiation process, PG&E and A&S held various meetings with individual A&S producers to attempt to persuade them the pricing terms were fair. Under NGMA regulations, producers had five working days to vote on the formal price proposal. If the proposal failed to receive requisite voter approval, the negotiation process would resume for another round.

In its Supplemental Report (Exh. 1103), DRA cites an excerpt from contracts between A&S and some of its largest producers which prohibited the producers from selling any gas directly to the PG&E retail market except through A&S. DRA sees this clause as directly thwarting competition.

C. Was the A&S Producer Pool and Producer Voting Mechanism Anticompetitive? Were One-On-One Negotiations Preferable?

1. Positions of Parties

PG&E states that the A&S producer pool arrangement was not a "cartel," but merely complied with provisions of the Alberta Natural Gas Marketing Act which it claims "institutionalized" netback pricing and prohibited the removal of netback gas from Alberta unless there is a finding of producer support.

DRA and SMUD contend that PG&E was impeded unduly in its ability to negotiate for competitive prices by its willingness to perpetuate the continuation of the A&S producer pool and voting mechanism. DRA and SMUD characterized the pool as a "cartel". SMUD defined a "cartel" as:

> "A voluntary, often international, combination of independent private enterprises supplying like commodities or services that agree to limit their competitive activities (as by allocating customers or markets...pooling returns or profits...fixing prices or terms of sale...or by other methods of controlling productions, price, or distribution)." (Webster's Third New World Dictionary.) (Exh. 1200, p. 8.)

SMUD applies this definition to the A&S pool, asserting that it successfully cut off competition among its members and was granted exclusive access to the PGT pipeline, the only direct transport link between northern California and the gas-producing basins of Alberta.

IPAC criticizes DRA for characterizing the A&S pool arrangements as if they instantaneously materialized in 1988. The A&S producer pool relationship dates back to the 1960s when PG&E established A&S as a wholly-owned subsidiary to aggregate supplies for the Alberta-California Pipeline Project. IPAC believes the benefits this arrangement has afforded ratepayers over the past

30 years must be factored into the assessment of its performance over the 1988-90 record periods.

IPAC disputes any characterization of the A&S producer pool as being anticompetitive and strongly objects to DRA/SMUD's use of the term "cartel" in describing the pool. IPAC defends the pooling of supplies by a single aggregator as a common business practice within Canada. Such pooling avoids the economic inefficiency of aggregators attempting to negotiate every price change with each one of hundreds of producers. IPAC further contends that actual negotiations with members of the pool extended far beyond the formal ballot process and included numerous face-to-face discussions between PG&E/A&S personnel and individual producers.

Moreover, IPAC contends that the A&S pool operates in a manner and under arrangements which are quite similar to the manner in which PG&E purchases gas produced in California. Subsection 785(a) of the California Gas Policy Act (CGPA) requires gas utilities to purchase "that gas which is produced in the State of California having an actual delivered cost equal to or less than other available gas." This legislation specifically prevents California producers from being "discriminated against" and guarantees California producers preferential sequencing of their gas sold to California utilities based upon competitive delivered cost. The contracts underlying California producer sales are typically for a 20-year term, with price redetermined annually. IPAC finds it contradictory that DRA on the one hand criticizes the A&S pool mechanism while finding no problem with the CGPA mechanism.

DRA contends that PG&E's ability to negotiate lower gas prices was unduly impaired by the power of the producer voting mechanism. According to DRA, under the voting mechanism, only a few big producers, representing a major share of A&S's contracted supplies, were able to control the vote and dictate the price.

During the record periods, the 10 largest A&S producers controlled 80% of the A&S gas supply.

A&S sent a letter to the APMC in October 1987 complaining that the voter mechanism allowed the top two or three A&S producers to veto a proposed contract change supported by the majority of suppliers. Notwithstanding its concerns, A&S extended the voter mechanism provisions in November 1988. By the end of 1989, the APMC had amended the voting mechanism to require a 51% majority by number and 60% by volume (down from 70%).

DRA claims that PG&E was unreasonable in buying gas under the APMC's netback voting mechanism instead of negotiating prices individually with producers when it had the opportunity to do so. On at least two specific occasions, PG&E had the option to modify the netback pricing provisions of the A&S/producer contracts. For example, the netback agreement under the A&S/producer contracts was due to expire on October 31, 1988. Since PG&E did not object at that time, A&S maintained the netback provisions and extended them through October 31, 1990. In the 1990 price determination, PG&E agreed to extend the netback provisions through July 31, 1991.

DRA argues that if PG&E had refused to extend the netback pricing provisions on October 31, 1988, PG&E could have introduced alternative pricing methods referenced to prices being charged to other gas customers within Alberta. Without the netback provision, A&S would not have been subject to the NGMA voting rule. Instead, DRA believes that the Alberta producer "cartel's" power was unnecessarily maintained, allowing it to extract the highest possible price from California consumers via the netback arrangement.

PG&E defends its decision to continue the netback voting mechanism in October 1988, stating that it did evaluate the merits of the voting mechanism in 1987 and 1988. PG&E argues various problems would have arisen had it opted to discontinue the voting mechanism and these unresolved problems justified its decision to continue the mechanism in place. Individual producers could have held out for an even higher price than the one adopted, or else could have gone to price arbitration or reclaimed their reserves for use in another market.

PG&E cites the following consequences as justification for its decision not to elect one-on-one negotiations:

> Increased opportunities for Alberta regulatory intervention and for a return to the high regulated Canadian prices from the early 1980s.
>
> Prospects for price arbitration with Alberta producers with a resolution unfavorable to PG&E, resulting in uncompetitive Canadian prices in California.
>
> Disruption of TOP settlements and recovery arrangements which had been put into place, since all contract terms and conditions would have to be renegotiated.
>
> Difficulty of administering individually negotiated contracts.
>
> Deviation from the practice of all other major aggregators who had adopted netback agreements.

Contract renegotiation also could have required a review of the A&S provincial gas removal permit and the A&S gas export license. These contractual changes could have hampered PG&E's efforts to secure a long-term export license through 2010.

PG&E alleges that it lacked sufficient buyer market power to influence prices to the extent assumed by DRA. PG&E purchased only about 13% of Alberta gas over the record periods. The Alberta government owns 85% of the natural gas at issue which gives it much more seller market power.

2. Discussion

The voter mechanism posed a number of impediments to the full operation of a truly competitive market. Nonetheless, given the negative consequences PG&E would have risked by terminating it, PG&E followed a prudent course by opting to continue the producer voting mechanism through the record periods. The voting mechanism foreclosed the possibility of price competition among the A&S producers themselves for PG&E market share. By definition, only a single price could be negotiated for the entire producer pool. It is unnecessary to decide whether the A&S pool is a "cartel." It is more constructive to evaluate the underlying structure of the arrangement itself in terms of consequences to PG&E ratepayers.

Although we acknowledge that some additional administration would have been involved in one-on-one negotiations, PG&E presents no definitive quantitative analysis weighing the costs of such increased administrative complexity against potential cost savings from one-on-one negotiations. Even under the voting mechanism, PG&E/A&S still experienced significant one-on-one discussions with individual producers.

As pointed out by DRA, the voter mechanism effectively gave large producers a veto of a proposed price change that the majority of suppliers might favor. For example, in the 1989 negotiations, a few major producers were able to block agreement on PG&E's price offer. Only after PG&E persuaded one of these large producers to support a revised offer, did the requisite voting majority adopt the price. Under one-on-one negotiations, PG&E could have stimulated competition among the A&S producers for a share of PG&E's market. PG&E could reward individual producers with increased takes in exchange for lower prices.

We concur with IPAC that on the surface there appear to be similarities between the A&S producer voting mechanism and the CGPA pricing policies. Differences may also exist. For example, IPAC did not compare the relative market power among California producers with that of members of the A&S pool which is dominated by a few very large producers. To the extent similarities exist, we shall apply consistency in the standard to which both producers in California and in Canada are held. In both cases, this standard requires producers to price their gas "equal to or less than other available gas." We shall examine the reasonableness of PG&E's gas purchases from California producers as part of Phase IIb of this proceeding. But if PG&E were to buy California gas for a price above competitive alternatives, it would be inconsistent with the CGPA, and PG&E would be at risk for a disallowance just as much as for a similar overpayment for Canadian gas.

D. Assuming the Producer Voting Mechanism Remained in Place, Could PG&E Have Negotiated Lower A&S Contract Prices?

DRA and PG&E have conflicting views over the standard against which to judge the prudence of PG&E's negotiations with A&S suppliers. We consider below the positions of parties as to the reasonableness of PG&E's negotiations with A&S producers on a year-by-year basis, then we discuss our evaluations of each year's results and present our overall conclusions concerning the prices PG&E could have negotiated with the A&S producer pool.

1. Positions of Parties

a. 1988 Price Redetermination

As the 1988 record period began, the A&S price on a delivered basis was $1.81 per MMBtu which had been in effect since October 1986 (Tr. 7961:25). The price was subject to redetermination effective April 1, 1988. PG&E's goal in the 1988 price determination was to maintain the price of $1.81/MMBtu for another year. PG&E cites the high cost of Southwest spot and commodity gas in the spring of 1988 as reducing its leverage to negotiate a lower A&S price on April 1, 1988. PG&E knew that it would reduce to zero its takes of El Paso commodity gas, given PG&E's expectation of an El Paso price of $3.30 per MMBtu effective April 1988. In these negotiations, one major producer advocated a price up to $2.60/MMBtu, the gas-equivalent cost of fuel oil, representing an alternative supply to the UEG load (Exh. 1753).

PG&E's commodity rate analysis summarized prices from a number of sources. Figure 3G of Exhibit 1008 summarizes the sources ostensibly considered. One of the listed factors is Alberta market prices. During 1988, PG&E asserts that it did attempt to invoke intra-regional price comparisons in its Canadian price comparisons. A&S producers were not swayed by such arguments, according to PG&E. A&S producers did not believe PG&E had access to an alternative long-term Canadian supply source or could access short-term gas in Alberta as a substitute source.

PG&E pointed out to A&S producers that our new industry restructuring rules were to be implemented May 1, 1988. Under the new rules, noncore customers would have the option of bypassing PG&E if its gas prices were not sufficiently competitive. PG&E's then-existing base of core customers comprised only about 40% of its gas market. In order for PG&E to continue to sell large volumes of gas, it would need to retain a large share of its noncore market. A&S producers were told that their price must be competitive enough to induce a large share of noncore customers to elect into the core if they were to continue to enjoy the benefits a high load factor. A&S producers were receptive to offering price terms which would allow them to serve the core elect. Thus, A&S producers accepted PG&E's proposed $1.81 price virtually unanimously.

PG&E computes that its negotiated A&S price saved ratepayers $10.2 million during 1988, compared to the cost of supplies in the U.S. Southwest. PG&E attributes this savings largely to the bargaining leverage which was provided by its large core-elect market.

DRA and SMUD present general criticisms of the price negotiations covering the full three-year period, but do not present any specific discussion of the 1988 price negotiations. TURN did not study the 1988 negotiations. DRA's criticism relies principally on the fact that PG&E failed to be aggressive enough in invoking intra-Alberta prices as a basis for PG&E's negotiating stance. DRA finds fault with A&S prices by comparing them unfavorably with intra-Alberta market prices. PG&E praises its A&S prices by comparing them with alternative U.S. Southwest gas prices.

b. **1989 Price Redetermination**

Given the market factors in early 1989, including a perception of declining gas supplies and rising spot prices, PG&E contends that it was virtually impossible to secure an A&S contract price less than the then-existing A&S rate of $1.81/MMcf. Thus, PG&E initiated 1989 negotiations by informally proposing to keep the price at $1.81. A&S producers' response to PG&E's proposal was "overwhelmingly negative" (Exh. 1008, p. 3-37).

A&S informally proposed a second offer of $1.87 for the first year and $1.95 for the second. Producers resisted a two-year commitment at any price, anticipating rising prices over the period.

PG&E/A&S then submitted a formal offer of $1.90/MMBtu to last for 18 months for a formal vote through the producer voting mechanism. PG&E advised the producers that they must offer competitive prices if they were to retain the large UEG load and the 300 core-elect contracts due to expire in July. PG&E computed a price range for A&S purchases based upon competitive conditions in the U.S. Southwest (presumed to be PG&E's alternative market source). PG&E also contends that it referenced Alberta sales to Eastern Canada to support the $1.90 price. PG&E computed a range of prices on an average cost basis, compared with PG&E's proposal of $1.90. PG&E's "Commodity Rate Analysis" thus concluded that $1.90 was the "highest price PG&E's market can absorb while keeping the core portfolio attractive for core-election."

PG&E's 18-month proposal was rejected by a few major producers, thus yielding an insufficient majority for adoption. Thus, the 1988 contract price extension expired on March 31, 1989 without agreement on a new price. The NEB, at this point, announced that a new interim price of $1.90/MMBtu would go into effect for one month, and that in the future, a contract price would expire at the end of its term if no agreement on price had been reached.

PG&E/A&S continued negotiations during the following month. By reducing the term from 18 to 15 months, PG&E was able to convince one large producer who had vetoed the earlier offer to support the revision. Thus, in the 1989 price redetermination, PG&E and A&S ultimately negotiated a price of $1.90 per MMBtu to be fixed for 15 months.

DRA interprets PG&E's language that the $1.90 price was the "highest that the market could absorb" as evidence that it accepted the highest price it possibly could for A&S gas while keeping it preferentially sequenced relative to Southwest alternative supplies. In light of alleged oversupply conditions in Alberta throughout the record periods, DRA faults PG&E for not negotiating lower prices relative to competitive spot prices.

TURN argues that PG&E was aware of Canadian gas prices well below the $1.90 it offered to A&S producers in 1989. In its contemporaneous PG&E/PGT Expansion A.89-04-033, PG&E referenced $1.20 to $1.80 as the range of "current Alberta netbacks." TURN raised its concerns in PG&E's next available ACAP rate proceeding in which it testified it was by then "common knowledge in the natural gas industry that sales to PG&E's A&S subsidiary provided A&S producers with the highest netback prices available in the province." (Exh. 1300, p. 12.)

PG&E contends that prices which DRA characterizes as "high end" were much lower than A&S producers were initially demanding. PG&E portrays its price offer as merely casting its opponents' position in a positive light to convince them that they were getting a fair compromise.

c. <u>1990 Price Redetermination</u>

Relevant conditions changed by the time of the 1990 price redetermination. PG&E accordingly developed a different pricing proposal for its 1990 price redetermination, to become effective July 1, 1990. By PG&E's own admission, the perceived U.S. Southwest supply scarcity problems encountered during 1988 and 1989 began to moderate by early 1990. Thus, PG&E was able to use lower cost Southwest spot prices to induce long-term Southwest suppliers to reduce their prices and to add additional Southwest supplies. Within Alberta, increased capacity on the NOVA pipeline, without concurrent downstream capacity, created "distress gas" prices since producers were obligated to pay demand charges on the NOVA system with no immediate market for their gas. In light of the improving supply conditions, PG&E formulated a new gas purchase policy effective May 1990. It features were:

(1) Reducing the price differential below which long-term supplies would compete with short-term supplies from $0.20 to $0.10 per MMBtu;

(2) Eliminating the 1200 MMcf/d core-demand volume that long-term suppliers would have the first opportunity to serve; and

(3) Explicitly including inter- and intra-regional supply diversity and price competition as criteria in its A&S producer price renegotiations.

PG&E incorporated its revised policy into its 1990 price negotiations with A&S producers. PG&E initially offered A&S producers a two-tiered pricing structure in a formal submission to the NEB. Tier I would cover purchases up to 700 MMcf/d priced at $1.90/MMBtu at Kingsgate. Tier II would cover purchases of volumes up to 350 MMcf/d for April through October, and 200 MMcf/d for November through March. For the winter months of December through February, Tier II pricing would not be used and the Tier I price would apply to all purchases. Tier II volumes would thus cover approximately 24% of total A&S sales. Tier II volumes would be priced at the AMP as published monthly by the APMC. The Tier II price would be triggered for volumes in excess of Tier I volumes whenever the AMP was more than $0.10 below the Tier I price.

PG&E's pricing proposal was rejected by the A&S producers (89% by volume). The producers objected particularly to linkage of Tier II prices to the AMP. Producers were also responding to a perceived threat of lost market share as a result of Commission R.90-02-008 rules potential to reduce substantially PG&E's ability to market gas to noncore customers. As the June 30 contract deadline approached with no agreement, the NEB approved a one-month contract extension to permit negotiations to continue without supply disruption.

PG&E then recast its price proposal, increasing the Tier II price from $1.40 to $1.50 per MMBtu. After A&S advised PG&E of the expected negative producer reaction and potential for Canadian government intervention, PG&E and A&S filed a second formal price offer, holding the Tier I price at $1.90 and increasing the Tier II price to $1.60 per MMBtu. A&S further advised producers that if this offer was not accepted, it would seek to sign contracts with individual producers to ensure sufficient gas in August to serve PG&E's core market. A&S simultaneously filed short-term contracts with all producers, offering the same price. Likewise, PG&E signed additional long-term Southwest contracts to demonstrate to Canadian producers that, without some compromise, they risked loss of market share. When ultimately faced with the prospect of going to individual short-term contracts and the possible loss-of-market share to the U.S. Southwest, or to each other, the A&S producers decided to accept A&S's offer on July 25, 1990.

TURN responds that while PG&E finally introduced the issue of competitive gas prices within Canada in its 1990 price redetermination, it was limited only to its Tier II volumes. TURN criticizes PG&E for still failing to undertake steps to position itself to purchase significant quantities of non-A&S Canadian gas.

2. **Discussion**

We first offer general observations concerning the common elements of the price renegotiations covering the 3-year record period. Then we address the specific negotiation process conducted for each year of the record period.

The dispute over the reasonableness of PG&E's price negotiations under the producer voter mechanism turns largely on the proper benchmark against which A&S producer competition should be measured. If we were to accept the premise that U.S. Southwest gas was the only viable benchmark for A&S gas competition, then we would conclude that PG&E's costs for A&S gas were competitive. However, U.S. Southwest prices represent only one possible benchmark. Competitive alternatives within Alberta also merit consideration in evaluating the competitiveness of A&S gas. As discussed in Section VI, PG&E could have positioned itself to access Alberta gas alternatives for volumes in excess of 700 MMcf/d. We conclude that PG&E could have induced the A&S producers to accept a lower price for at least a portion of contracted volumes had PG&E succeeded in establishing as a competitive benchmark the price of alternative gas supplies within Canada during each of the record periods.

Although PG&E nominally cited intra-Alberta prices as a competitive force in the 1988/89 negotiations, neither side to the negotiations seriously treated alternative Canadian supplies as a realistic competitive threat. Although PG&E explicitly introduced intra-Alberta prices into its 1990 negotiations, it was a case of too little too late. PG&E had failed to position itself to pose any credible threat of having access to alternative sources of Canadian supplies.

PG&E could have taken steps to pose a credible threat to procure alternative sources of Canadian supplies. Had it done so, PG&E could have applied genuine leverage on A&S producers either to consider Canadian price alternatives in negotiations or else risk losing the load factor benefits enjoyed through core election. We conclude that A&S producers would have acted in their own best interests to retain PG&E sales by matching the price of potential Alberta supply alternatives, at least up to the point where PG&E's netbacks exceeded opportunities from competing buyer alternatives.

Had A&S producers refused PG&E's offer, they would have had to seek an alternative market for the portion of their gas not taken by PGT/PG&E. A&S producers likely would have sought alternative markets either in eastern Canada or the U.S. according to PG&E. It is not obvious, however, that A&S producers could have quickly or easily marketed all such gas in alternative markets at prices equal to the netbacks enjoyed through the PG&E market. As IPAC points out, there were structural market constraints on a producer switching sales from one export market to another. IPAC finds this fact consistent with PG&E's pricing model results. Yet, a demand for Canadian gas in U.S. export markets did exist. IPAC notes that PG&E was increasingly in competition with other U.S. buyers for firm long-term Alberta natural gas supplies. To the extent other markets had lower-priced burner tip alternative supplies, however, Alberta producers may have been unable to obtain as high of a netback in those markets as they would receive from selling the gas to PG&E on a short-term or spot basis. As PG&E's pricing model shows, in export markets with excess capacity or depressed demands, Alberta producers had to reduce prices down to the value of the buyers' market alternatives.

On the other hand, PG&E's market represented considerable value to the A&S producers relative to plausible alternatives. As IPAC states, A&S producers relied heavily on commitments of PG&E via A&S to purchase contractually specified volumes at market-competitive prices to provide them with financial returns upon which pipeline investments were predicated. (Exh. 1402/Anderson.) Rather than run the risk of replacing these sales at less lucrative prices, it would have been in the A&S producers' interests to meet PG&E half way in negotiating a price.

Further evidence of the high value of the PG&E's market relative to A&S's alternatives is the manner in which A&S producers responded to the core-elect market. A&S producers discounted their prices in exchange for the opportunity to serve PG&E's large core-elect market. It would be economically rational for A&S producers to accept a lower price in exchange for a greater market share only if there was an economic value to the increased market share relative to producers' alternatives.

The value of the core-elect market to A&S producers can be characterized by two elements: (1) the increased volume of sales and (2) the netback price per MMcf. Each of these elements helped contribute toward recovery of the A&S producers' fixed costs and return on investment. Yet, the additional core-elect sales would only have value to the extent they represented sales which could not be made in an alternate market at an equal or greater netback. While PG&E realized some price concessions with respect to core-elect volumes, PG&E failed to extract commensurate price concessions on the per-MMcf unit price profit for core-elect volumes.

We conclude that PG&E and A&S producers could have mutually negotiated an overall deal with each other at least as good as either could negotiate with others during the record period. Nonetheless, by failing to establish intra-Alberta prices as a valid benchmark for pricing at least a portion of A&S gas, PG&E failed to achieve the most favorable prices which it could have in negotiating with A&S producers. Given the desirability of the PG&E market to A&S producers, we believe they would have accepted PG&E's lower offer had PG&E posed a credible threat of having the capability to locate alternative Alberta supplies at lower costs, to overcome any perceived market impediments, and to transport such gas to PG&E's end-use market.

We have already quantified in Section VI a reasonable market price and volume level at which PG&E could have procured independent Alberta supplies outside the A&S pool. While we cannot pinpoint precisely the best price that PG&E could have negotiated with the A&S pool, we believe that the market value of incremental gas outside of the pool as we have quantified it forms an appropriate proxy for a price proposal to the A&S producers. Thus, PG&E could have offered to pay the A&S price which resulted in an equivalent savings of $90.133 million over 1988-90 which we have adopted as a disallowance in Section VI. Our market prices developed in Section VI provide a reasonable proxy of the amounts which PG&E could have offered. We believe this sharing reflects more precisely the relative bargaining power of each side to the price negotiations as compared to the pricing scenarios assumed by DRA/SMUD/TURN.

We address the specific circumstances as to the reasonableness of PG&E's negotiating strategy for each record period below.

a. **<u>1988 Price Determination</u>**

In its 1988 price renegotiations, PG&E failed to use the leverage of the newly inaugurated core-election program to its full advantage by requiring A&S producers to factor Alberta market price influences into its contract price. PG&E acknowledged the relevance of intra-Alberta prices in its negotiations with A&S producers, stating in its 1988 Commodity Rate Analysis that: "Gas-to-gas competition from Canadian suppliers other than A&S is a competitive force in PG&E's market." (Exh. 1022, p. 7.) PG&E claims that it pointed out to A&S producers that their netback prices were higher than that of other Canadian aggregators selling into alternative markets. (Exh. 1008, p. 3-30.) Yet, in the 1988 commodity rate analysis itself, there is no specific presentation taken steps earlier to position itself credibly to seek alternative Canadian supplies.

First, going into the negotiations, PG&E could have exerted its influence on PGT to grant it priority status on the PGT pipeline queue, thus giving it the flexibility to carry out a threat to bypass A&S producers. Second, PG&E could have approached alternate producers outside the A&S pool to discuss contingent price offers for prescribed incremental volumes in the event agreement could not be reached with the A&S pool. As discussed in Section VI, PG&E prudently could have found up to 300 MMcf/d of gas outside the A&S pool supplies. Then in presenting its initial price offer to the A&S pool, PG&E could have insisted that Alberta market forces be taken into account before turning over 100% of the PGT pipeline capacity to the A&S pool through high core election. initially PG&E could have offered the A&S pool no more than 700 MMcf/d, premised on a price outlined in Section VI. PG&E could then hold out to the A&S pool the prospect of serving additional core-elect load up to full PGT pipeline capacity, but only if the pool was willing to accept a price competitive with contingent offers which PG&E had been able to secure within Alberta. By framing the initial offer in this manner, PG&E could have more likely avoided the sorts of problems it encountered, for example, in 1990 where an agreement on 100% of A&S volumes was at risk because of a price dispute only over a portion of supplies. On this basis, a reasonable price for full takes of A&S pool supplies in 1988 is $1.65/Dth, as derived in Appendix D.

b. <u>1989 Price Determination</u>

In the 1989 price renegotiation, PG&E followed a similar strategy to that used during 1988. The main advantage over 1988 prices was the extended term of 15 months. Prices were once again, however, set without considering the significance of the Alberta market as a competitive force in PG&E's procurement options. PG&E's failure in 1989 to achieve even a continuation non-Alberta alternatives, and did not reflect potential Alberta market options outside of the A&S pool.

Based upon the precedent which we believe PG&E could have set in the 1988 negotiations, it could have followed a similar strategy in 1989. We derive an adjusted price for 1989 A&S gas as set forth in Appendix D of $1.71/Dth based upon full volume purchases.

c. <u>1990 Price Determination</u>

Notwithstanding its continuing assertions that intra-Alberta gas was not a viable competitive option during any of the record periods, PG&E explicitly invoked intra-Alberta prices as a bargaining tool in its 1990 negotiations. By PG&E's own admission, the market restrictions which it believes foreclosed availability of Alberta gas during 1988-89 grew more relaxed during 1990, as explained above.

Yet, PG&E's offer, which proposed only relatively modest recognition of Alberta prices, was opposed by A&S producers. PG&E thus withdrew its initial offer and replaced the AMP with a fixed $1.60 per MMBtu for valuing Tier II purchases, to which the A&S pool ultimately agreed. Thus, while the $1.60 would appear to reflect at least some implicit recognition of lower Alberta prices as competitive factor, it falls short of an adequate negotiated outcome.

What could PG&E have done differently to have induced A&S producers to accept an offer recognizing intra-Alberta prices as a legitimate market force? As noted earlier, the unwillingness of A&S producers to concede this point was based on their perception that PG&E lacked the will or the means to seek alternative Alberta supplies. The two primary steps that PG&E could have taken differently were (1) to firmly establish the legitimacy of the Alberta market as a factor in negotiations at the initiation of the restructuring program in 1988 and (2) to accomplish this task by positioning itself to take advantage of

We conclude that a significant factor in the negative environment of the 1990 price negotiations was that in previous years, PG&E had accepted that the A&S pool would be entitled to 100% access to PGT. Had PG&E followed a more aggressive intra-Alberta price strategy earlier, we believe PG&E could have elicited a price offer based upon the strategy we have outlined above for 1988/89. Accordingly, the 1990 A&S gas prices would have averaged $1.75/Dth, as shown in Appendix D.

VIII. Other Miscellaneous Anticompetitive/ Cross-Subsidization Issues

In addition to its specific proposals concerning excessive payments for A&S gas, DRA presented additional testimony concerning alleged anticompetitive practices of PG&E. While DRA did not assign any specific disallowance to these practices, it proposed that such practices should be taken into account in future consideration of restructuring and recovery of transition costs.

A. PG&E's Position

PG&E asserts that the producer contract provision criticized by DRA as being anticompetitive did not prevent Canadian producers from competing in PG&E's market with gas reserves not under contract to A&S. PG&E further claims that the contract clause has never been asserted or enforced by A&S and has had no effect on the quantity or price of Canadian gas imported into California or elsewhere.

PG&E explains that A&S's working interests in gas production for the properties questioned by DRA were acquired in the 1970s and arose from financing of certain gas exploration projects to secure long-term supplies for California ratepayers. Those interests constitute less than 0.7 Bcf of gas.

Regarding DRA's alleged overcharge of A&S Canadian transport costs, PG&E points out that FERC accepted these costs as prudent upstream pipeline charges in setting PGT's tariff. Further, under netback pricing, PG&E asserts that these demand charges were netted out of the revenues producers received, and thus did not increase PG&E ratepayers' prices. Finally, ratepayers were reimbursed for a portion of the demand charges to the extent revenue credits were received by A&S from NOVA for other interruptible shippers who used NOVA capacity when available.

B. <u>DRA's Position</u>

DRA found that A&S had amended several of its contracts with some of its largest producers to include the provision that if A&S does not purchase full contract quantities from a producer, that producer may not separately sell gas in PG&E's service area. DRA believes this provision thwarted competition within California since it limited sales by major Canadian producers into PG&E's market and helped ensure that A&S producers did not compete with A&S for sales into California.

DRA further contends that A&S was a partner with specific A&S producers and had a vested interest in certain oil wells and gas plants. PG&E had not quantified the extent of A&S's royalty share from working interests in gas plants which produced gas for sale to A&S. Based on this information, DRA believes A&S had a conflict of interest with respect to gas sold to PG&E. While presumably negotiating with producers for a competitive price, it would also have a shared agenda with these producers with respect to its working interest in royalties.

DRA contends that PG&E ratepayers appear to be paying fixed demand charges for firm transportation on the NOVA and ANG pipeline facilities which are in large part on standby to serve peak load of Canadian markets. The A&S fixed demand charges are billed directly to PGT through A&S with subsequent adjustment for offsetting revenues received from third parties, according to DRA.

C. Discussion

We find that the contract clause challenged by DRA has not produced any actual harm to ratepayers during the record period. On the other hand, PG&E fails to explain what ratepayer interests are served by having the clause restricting sales under contract to A&S. Although PG&E states it has never enforced the provision, it's unclear whether this is simply because producers have never violated the provision or because PG&E believes it is not appropriate to restrict competition in this manner. In any event, we find that the contract clause runs counter to our stated goal of competitive access by ratepayers to a variety of alternative supplies. We may further consider any anticompetitive implications of this contract clause in a future reasonableness review or in considering PG&E's prospective restructuring of its Canadian supply arrangements.

Regarding the alleged conflicts of interest in gas production investments by A&S, we find no material financial interest is involved. Even assuming all of that gas from A&S's working interests was ultimately sold to PG&E, this represents less than 0.07% of PG&E's gas purchases during the record periods. We find this impact to be immaterial.

We note that DRA is investigating potential conflicts of interest and upstream costs with respect to PG&E's Canadian affiliates as part of an audit in PG&E's A.92-04-001. We expect to address these questions further as part of that proceeding.

Findings of Fact

1. By D.90-05-029 (36 CPUC 2d 282), in A.89-04-001, the Commission deferred consideration of all PG&E gas reasonableness issues for record period 1988 to PG&E's 1989 record period reasonableness proceeding.

2. By D.90-10-062 (38 CPUC 2d 40) in A.90-04-003, the Commission deferred consideration of all 1988 and 1989 record

period gas reasonableness issues to PG&E's 1990 record period reasonableness proceeding.

3. Phase II-A of A.91-04-003 is the procedural vehicle for the Commission's consolidated consideration of the reasonableness of PG&E's Canadian gas procurement activities during the 1988, 1989, and 1990 record periods.

4. In retrospectively reviewing the reasonableness of specific utility gas procurement activities, the event or conduct is to be reviewed based on the facts and circumstances that were known or should have been known by the utility at the time the event or conduct occurred.

5. In retrospectively reviewing the reasonableness of specific utility gas procurement activities, the supply and demand conditions, the legislation, decisions, policies, and regulatory conditions in effect at the time constitute the foundation of the knowledge which should have been known to the utility and form a basis for evaluating the utility conduct.

6. In retrospectively reviewing the reasonableness of utility gas procurement conduct with respect to a specific source of supply, the relationship of that conduct and source of supply to the utility's overall gas supply procurement activity is an important consideration.

7. The reasonable and prudent act or conduct is not limited to the optimum, but includes a spectrum of possible acts consistent with the utility system need, the interests of the ratepayers and applicable statutes, regulations, and decisions and requirements of governmental agencies of competent jurisdiction.

8. The above standards and considerations are required to avoid the application of hindsight in reviewing utility decisions for reasonableness.

9. The burden rests heavily on a utility to prove with clear and convincing evidence that its actions were within the zone of reasonable conduct as framed using the above considerations.

10. Where other parties challenge the utility's showing as to its prudence, those parties bear the burden of presenting competent evidence in support of such challenges and in support of their ratemaking disallowances but the ultimate burden of proof of reasonableness is never shifted from the utility to the challenging parties.

11. Between 1978 and 1988, state and federal legislation and regulation fundamentally altered the California and United States natural gas industry in a way which encouraged the development of spot markets and resulted in greater gas competition.

12. The increased competition intended to result from the restructuring of the domestic natural gas industry provided a basis for this Commission to fundamentally restructure the regulatory mechanisms governing how gas was provided to California utility customers.

13. By D.86-03-057 (20 CPUC 2d 628), D.86-12-009 (22 CPUC 2d 444), D.86-12-010 (22 CPUC 2d 491), and D.87-12-039 (26 CPUC 2d 213) the Commission adopted and implemented policies and objectives governing the restructured gas industry.

14. D.86-03-057 (20 CPUC 2d 628) outlined a new natural gas industry regulatory policy which separated customers into core and noncore categories depending on the extent to which they had alternatives to system gas supply.

15. Among the CPUC's goals in the 1986 restructuring were (1) encouraging burner-tip competition; (2) promotion of open access; (3) protecting core ratepayers from inadequate supplies, market segmentation (with its risk of high prices to core customers without fuel alternatives) and significant price fluctuation which could lead to "rate shock"; (4) avoiding bypass of the intrastate gas system via fuel switching; (5) encouraging throughput on the pipelines serving California, in order to maximize the contribution by noncore gas customers to pipeline system fixed costs; and

(6) securing the commodity price benefits of competition for the "captive core" to the greatest extent possible.

16. D.86-12-009 (22 CPUC 2d 444) required California utilities to continue providing procurement service for noncore customers out of either a core or noncore gas supply portfolio.

17. D.86-12-010 (22 CPUC 2d 491) established criteria which California utilities were to use in assessing competing supplies for their core gas supply portfolio. Utilities were to procure supplies in a manner which reasonably resulted in certainty of supply availability to meet core-peak requirements, price security greater than would be the case using spot supplies, and to achieve both at the lowest possible cost.

18. D.86-12-010 also noted the lack of empirical evidence upon which to establish specific guidelines as to the percentage of long-term gas to hold in the core portfolio.

19. D.88-03-036 noted that while reasonableness standards can be clarified through the adoption of guidelines, such guidelines are only advisory in nature and do not relieve the utility of showing that its actions were reasonable.

20. As reflected in D.86-12-010 (22 CPUC 2d 491), the core-elect option was one of the Commission's major vehicles for capturing the benefits of competition for core customers.

21. Although open access for noncore customers was an important goal, the first priority for the Commission and for the utilities it regulates was the operation of the gas system for the benefit of core customers.

22. In D.88-12-099, our stated reason for retaining the core-elect option was based on a tactical perspective with the expectation that PG&E would use it as an aggressive bargaining chip in negotiating with A&S producers.

23. During the three record periods, the Commission did not permit PG&E to purchase gas for its UEG outside of the core or noncore portfolios. Throughout the record periods the only UEG gas

supply options open to PG&E were to purchase from PG&E's core or noncore portfolios.

24. PG&E's decision to commit 100% of its UEG load to core election during the record periods provided it with a significant bargaining chip.

25. While PG&E used core election to bargain for A&S prices competitve with U.S. Southwest levels, PG&E failed to effectively use core election as bargaining leverage to align A&S prices more closely with competitive market forces within Alberta.

26. While PG&E could have successfully purchased volumes below A&S prices, individual noncore customers acting on their own likely could not have purchased gas below A&S prices given the constrained capacity on PGT and transport access rules which were in place for rationing capacity under the Section 311 queue.

27. TURN has presented credible evidence that PG&E could have obtained a better result in the Canadian price negotiations during the 1989-90 record periods.

28. During each record period PG&E achieved the Commission's procurement directive in D.86-12-010 to acquire a reliable core portfolio with "certainty of supply availability to serve core-peak requirements, [and] price security" but failed to satisfy the Commission's directive to achieve their objectives at the lowest possible cost.

29. In response to D.86-12-010 (22 CPUC 2d 491) PG&E stated a revised gas purchase policy in 1987. PG&E's purchase policy was designed to take advantage of the core election structure adopted by the Commission, in order to obtain the benefits of competition for core procurement customers.

30. PG&E's 1987 purchase policy was designed to promote competitive prices relative to U.S. Southwest gas by offering all longer-term gas suppliers high takes in exchange for a price that was competitive with PG&E's existing suppliers and fixed for at least 12 months.

31. As applied during the 1988/89 price renegotiations, PG&E's 1987 purchase policy failed to promote the potential to lower prices by seeking to stimulate competition between the A&S pool and other prospective suppliers in Alberta.

32. PG&E's 1987 purchase policy included a downward "flex pricing" mechanism so that PG&E's long-term suppliers would have to meet or beat the price of spot gas but only for supplies in excess of 1,200 MMcf/d.

33. The downward "flex pricing" mechanism results in very minimal impacts on ratepayers either positively or negatively.

34. While PG&E procured short-term gas from the U.S. southwest, it procured virtually no short-term gas from Canada during the record periods.

35. The evolution of the natural gas industry occurred differently in Canada because of a different ownership and regulatory structure.

36. Export of natural gas from the Canadian province of Alberta and across the international border is governed by an extensive set of federal and provincial regulations.

37. Provincial regulations governing the removal of natural gas from Alberta are designed to ensure that removal is only authorized where the action is in the Alberta public interest.

38. The extent to which any permit for removal of natural gas from Alberta is determined to be in the public interest is dependent upon the quantity, term, and price of the gas being removed, among other considerations.

39. In Canada, mineral resources, including natural gas, are largely owned by the provinces who have the power to regulate their sale.

40. Although the Province of Alberta owns 85% of Alberta's natural gas reserves, the province does not itself develop, produce, or market its natural gas resources.

41. The Province of Alberta regulates the removal of natural gas through the control of intraprovincial pipelines, such as NOVA, which are necessary to move the gas to provincial borders.

42. Canadian national regulation of exports of natural gas by the National Energy Board (NEB) also requires that long-term export arrangements be found to be in the Canadian public interest.

43. The provincial removal permits and Canadian federal export licenses in place that authorized the sale and transport of Alberta gas into the northern California market would not have provided for the purchase of short-term gas by A&S, PG&E, or any other party for resale into the northern California market. Although PG&E would have had to acquire separate short-term removal permits, PG&E's own witness's assessment was that Canadian governmental approval of short-term exports since 1987 generally had become perfunctory (Exh. 1128).

44. Alberta's policies against self-displacement and short-term sales to core customers would not have precluded short-term sales into PG&E's market. Any attempt to implement such sales would likely not have jeopardized A&S existing removal permit applicable to captive core volumes.

45. Canadian federal influence over gas exports is also exerted through control of interprovincial pipelines, such as Alberta National Gas Pipeline (ANG), which are necessary to move the gas between provinces or to the international border.

46. The NEB historically used a reserve-based assessment method to determine whether the Canadian public interest would be harmed by a proposed export.

47. A reserved-based export authorization methodology provides increased supply reliability to the purchaser.

48. As the U.S. natural gas industry was moving to a more competitive structure in the several years before the record

periods, the Canadian gas industry was moving away from government-administered pricing, and toward end-use, market oriented burner-tip pricing.

49. Under Alberta's Natural Gas Marketing Act (NGMA), "netback gas" refers to gas for which the shipper (aggregator) pays a price "calculated wholly or partly by reference to a price or prices payable to the shipper on the resale of gas by him."

50. Under the NGMA, members of the A&S producer pool received revenue determined by netting back from the A&S/PGT resale price the transportation and other costs incurred between the wellhead and the downstream point of sale.

51. The NGMA requires a finding of producer support for the resale price of "netback gas."

52. The NGMA contains no language which can reasonably be construed to require that the resale price of gas aggregated by A&S and delivered to PGT, be tethered to the price of PG&E's alternative U.S. southwest supplies.

53. The A&S/PGT International Contract, as amended in November 1984, provided for periodic redetermination of the A&S/PGT resale price such that the price "is competitive with the price of major competing energy sources in the market of Pacific Transmission's customer, P.G.andE.."

54. PG&E has stated that, under the A&S/PGT International Contract, netback pricing is "not a specific legal requirement, but rather a mechanism by which market pricing can occur."

55. PG&E has stated that the pricing provision of the A&S/PGT International Contract "was a very broad based market measure that allowed the company to negotiate with a whole menu of options."

56. Under the A&S/PGT International Contract, intra-Alberta prices were relevant to the determination of a price which was competitive in PG&E's market during the record periods.

57. We never intended for burner-tip competition to limit the range of supply basin options competing at the burner tip.

58. The emergence of the burner-tip competition framework for Canadian exports in 1984-1986 was consistent with (1) the Department of Energy/Economic Regulatory Administration's (ERA) 1984 import guidelines and (2) the Commission's encouragement of competition at the burner-tip, as reflected in D.87-05-069 (24 CPUC 2d 368).

59. The ERA has permitted competing imports of Canadian spot gas into the California market notwithstanding PGT's request for assurances that its long-term supply arrangement would not be threatened.

60. Recognizing the flexibility underlying the minimum take provision of the A&S/PGT International Contract, the ERA has not viewed full takes under the International Contract to be a foregone conclusion.

61. Consistent with the Commission's burner-tip competition philosophy, PG&E should have pursued and stimulated competition among Canadian suppliers, but failed to do so.

62. PG&E's revised 1984 Canadian gas supply arrangements provided the potential for supply flexibility, but PG&E failed to take advantage of this potential, to the detriment of PG&E's customers.

63. Although the gas purchased by PG&E during the three record periods through the PG&E/PGT/A&S contracts was imported pursuant to ERA authority, that authority was permissive, and did not require PGT to import any particular amount of gas.

64. ERA's finding that the PGT import arrangement was fair was premised on the substantial reduction in PGT's take-or-pay obligations and elimination of minimum physical take obligations from the A&S pool.

65. With the evolution of the domestic natural gas market and the emergence of a more competitive natural gas market in the Southwest, the restructured PG&E Canadian gas supply arrangements

created the possibility of beneficial increased interregional and intraregional competition.

66. PG&E has failed to show that any claimed financial risk to which it might have been exposed through PGT's earlier exercise of the option to obtain a blanket open-access certificate under Order 436, was significant enough to justify denying ratepayers the savings of millions of dollars in gas costs.

67. As the largest customer and 100% owner of PGT, PG&E could have fully insulated itself against any possible risk of pregranted abandonment associated with conversion of a portion of its firm sales to firm transportation rights on the PGT pipeline.

68. Throughout the record periods, Section 284.102 of the FERC's Part 284 Regulations (18 CFR Ch. I), in accordance with Section 311(a)(1) of the Natural Gas Policy Act (NGPA), permitted any interstate pipeline, without prior FERC approval, to transport natural gas on behalf of a local distribution company (LDC).

69. Throughout the record periods, Section 284.10 of the FERC's Part 284 regulations provided that any interstate pipeline which commenced NGPA Section 311 transportation or accepted an Order 436 blanket open access certificate, "agrees to offer, and is deemed to offer, every firm sales customer the option...to convert a portion of its firm sales entitlements under any eligible firm sales service agreement to a volumetrically equal amount of firm transportation service."

70. At any time during the record periods, PG&E could have directed PGT to commence NGPA Section 311 transportation on PG&E's behalf, for the purpose of obtaining a portion of its firm Canadian gas supply from sources other than the A&S producer pool.

71. At any time during the record periods, PG&E could have obtained from PGT interruptible transportation service under Section 7(c) of the Natural Gas Act (NGA).

72. PG&E has not shown that a supplier with an alternative Alberta gas source would have been unable to receive the removal

permit and the export license required to permit an export to PG&E to displace the current supply arrangement. The evidence supports the conclusion that the application of Alberta's core-market policy would not have precluded such displacement.

73. There is no credible evidence in the record that under the applicable Alberta provincial regulations Alberta short-term supplies would have been prohibited from being exported to displace long-term supplies dedicated to the A&S/PGT/PG&E supply arrangement.

74. Alberta's regulations require disclosure of specific terms of proposed sales of Alberta gas to downstream buyers.

75. Alberta regulatory authorities considered proposals to sell Alberta gas at a delivered price which is not competitive with the end users' competing energy costs in the end-use market to be against the province's public interest.

76. Canada's NEB requires a showing that a proposed export of Canadian gas would be in the public interest of Canada.

77. A proposed long-term export of Canadian gas that would result in a delivered price substantially below market alternatives would not have been perceived by the NEB as in Canada's national public interest.

78. A proposed short-term export of Canadian gas would require a provincial removal permit.

79. The Tier II and Tier III downward pricing mechanisms in the PGT/A&S contract were approved by the Commission. Volumes purchased under these mechanisms during the record periods were small.

80. During the three record periods PG&E's gas demands were increased due to unforeseen conditions.

81. During the three record periods, gas production from California and the Southwest, PG&E's only other significant non-Canadian sources of gas was decreasing.

82. During each of the three record periods PG&E purchased all quantities of California gas available to it. California gas could only supply roughly 10-16% of PG&E's core portfolio demand.

83. During each of the three record periods PG&E's Canadian gas supply arrangements, on both an average cost and incremental cost basis, provided less expensive gas than the cost of an equivalent quantity of gas from the Southwest.

84. During each of the three record periods no lower cost non-Canadian gas was available to PG&E. Canadian-supplied natural gas was the lowest cost out-of-state significant gas supply available to PG&E.

85. Under these circumstances it was prudent for PG&E to continue to purchase Canadian-sourced gas.

86. April 1987 was the date of the last price negotiation applicable to the Canadian PG&E/PGT/A&S producer contracts prior to the February 1, 1988 - December 31, 1988 record periods. The price resulting from that negotiation was in effect for 12 months through March 1988.

87. The price in effect for the gas PG&E purchased through the PG&E/PGT/A&S producer contracts for the 12 months starting April 1987 was found reasonable by the Commission in D.89-05-064 (32 CPUC 2d 76).

88. Because Commission policy supported price stability as one criterion in core supplies and defined long-term a price in effect for a year or more, a price that is deemed reasonable when the supply contract was entered into must be deemed reasonable for at least 12 months, absent any lower cost alternatives which may be taken consistent with the contract terms.

89. Because the price for long-term Canadian gas was negotiated for a year or more, the reasonableness of that price should be assessed on the basis of what was known or reasonably knowable during the time the price was being negotiated.

90. In that context, the price of gas purchased by PG&E through the PGT/A&S contracts was also reasonable for the period February through March 1988.

91. Throughout the three record periods, PG&E's realistic gas supply alternatives were California-sourced gas, Alberta gas delivered via NOVA, ANG, and PGT, and gas from the U.S. southwest delivered via El Paso.

92. During the three record periods the continuing decline in California gas production and the increased demand for gas within PG&E's service territory, exacerbated by continuing drought conditions, put considerable strain on the interstate pipelines serving California, and in particular, caused the PGT pipeline to be fully utilized by PG&E.

93. Any analysis of the gas supply options available to the California market must consider transport of that gas from the supply region to California.

94. Alberta was the only significant Canadian supply region during the three record periods with a direct pipeline to California.

95. PG&E's contention that sellers of long-term gas were given preference over A&S for firm transportation on both NOVA and ANG is unsupported by the evidence.

96. PG&E's wholly-owned subsidiary, A&S, was the legal owner of firm transport rights on NOVA and ANG which were used to deliver gas from the A&S producer pool.

97. The rights of the A&S pool to sell gas into PG&E's market beyond 50% minimum take levels using NOVA and ANG transport facilities was contingent upon the price of the gas being competitively priced relative to PG&E's market.

98. The California gas market experienced supply problems from the U.S. southwest during the first two record periods.

99. Southwest spot gas unreliability contributed to higher domestic spot gas prices during the first two record periods.

100. The CPUC, CEC, and other industry observers recognized the unreliability of spot gas in the southwest although the reliability southwest spot gas improved in late 1989, continuing into 1990.

101. During the first two record periods gas producers in the U.S. southwest were generally unwilling to sign contracts that obligated the producers to supply specified volumes of gas at a fixed price for over a year. Producers were not willing to enter into such agreements until late 1989.

102. During the first two record periods, PG&E entered into multi-month supplies (with terms between 3 months to 6 months) as a hedge against price and supply availability uncertainties of monthly spot gas during the winter.

103. Under the gas portfolio accounting rules we established in D.86-12-010, gas purchase terms exceeding one month were treated as long-term gas.

104. On a total system basis, PG&E's purchases of long-term gas exceeded 80% of total purchases throughout the record periods.

105. PG&E did not provide a quantitative analysis of the necessary mix of long-term versus short-term gas supplies to provide a proper balance between lowest cost and service reliability.

106. Our basic guideline for long-term supplies during the record periods was that a majority of the core portfolio be composed of long-term gas, but we left it to the utility to determine the proper mix of short term versus long term.

107. Any price stability benefits which may have been offered under the annual A&S price redetermination should have been weighed against the potential lost opportunity to capture downward trends in spot prices by being locked into long-term commitments.

108. Given the market conditions, the perceptions of supply inbalances and higher prices, and Commission policy about secure, price-stable supplies, PG&E was justified in procuring the majority

of its Canadian supplies through long-term contracts, but has not shown it was justified in total reliance on long-term Canadian supplies to the exclusion of more competitively priced short-term alternatives in Alberta.

109. In 1986, the rate at which gas wells under contracts to A&S were producing gas was declining each year by about 75 MMcf/day.

110. In 1986, A&S advised PG&E that declining well deliverability, sequential contract termination starting in 1990, and the possibility of gas being released back to producers at their request called into doubt the adequacy of the existing supplies under contract to meet PG&E's peak demands.

111. DRA's allegation of overcontracting by A&S during the record periods was based in part on an incomplete and incorrect understanding of (1) the daily contract quantity (DCQ) and its relationship to average day system demand instead of peak-day system demand, (2) the DCQ as measured in the field and the DCQ available at the PGT pipeline, and (3) the normal pattern of deliverability decline as reserves are produced.

112. In view of the declining deliverability and the prospect of declining supplies as contracts terminated, it would have been prudent for PG&E to support A&S in its efforts to extend its contracts and related export licenses beyond 1994 for volumes sufficient only to serve only its captive core market. Instead PG&E also sought to extend its contracts for core-elect load, as well.

113. While core-elect customers only signed one-year contracts with PG&E for the core-elect commitment, PG&E (through A&S) signed multi-year contracts with A&S producers to serve core-elect load.

114. PG&E management noted in 1990 that the take obligations under A&S supply contracts may be impossible to meet if the CPUC were to limit PG&E's merchant role through the core-elect program.

115. In 1987, A&S applied to Canada's NEB for an extension of the existing export license (due to expire on October 31, 1994) which authorized the export of Canadian gas to the Northern California market.

116. At the time A&S sought a license extension, Canadian regulation required applications for export licenses to be supported by evidence of long-term dedicated gas reserves, and contracts which included minimum take obligations and a pricing mechanism which would result in a price for Canadian gas roughly equal to the delivered cost of competing energy alternatives in the end-use buyer's market.

117. At the time of the application to the NEB there was substantial growth in exports of long-term Canadian gas into United States consuming markets other than California, reflecting the increased interest of Canadian producers in competing for U.S. market share.

118. Even with record Canadian gas sales in 1988, one of PG&E's own witnesses placed the current surplus deliverability of Canadian gas at 1.4 tcf. (Exh. 1128).

119. By the 1990 record period, tight Southwest gas supplies and market conditions began to moderate somewhat and the need to rely on the A&S supply began to abate somewhat. The more relaxed conditions led PG&E to increase the percentage of Southwest long-term gas in PG&E's core supply portfolio and to begin to promote intra- and interregional price competition.

120. In April of 1988 the commodity cost of pipeline sales gas on the El Paso system was $2.92/MMBtu.

121. The 1988 price renegotiation resulted in a Tier I commodity cost of $1.81/MMBtu at the Canadian-U.S. border for purchase of long-term Alberta gas supply for a term of 12 months.

122. A component in the negotiations with Canadian producers was the argument that a Tier I price of $1.81/MMBtu would encourage

significant core election, by which Canadian producers selling long-term gas could maximize sales volume.

123. Although PG&E's core-elect load was an important bargaining chip in the 1988 price renegotiation, PG&E failed to use this bargaining chip to extract price concessions which took into account intra-Alberta competition.

124. Although PG&E failed to use the bargaining chip of core election to full advantage, absent any core election, the price of gas negotiated in 1988 would have likely been even higher.

125. Although very high core election made the core portfolio a more attractive market to A&S producers, core ratepayers were deprived of a fair share of the economic rents associated with that market by PG&E's failure to bargain aggressively.

126. In its 1988 Commodity Rate Analysis, although PG&E made mention of the interest of other Alberta producers outside of the A&S pool in selling to PG&E, PG&E did not ask A&S to meet the prices offered by other Alberta producers.

127. While PG&E's 1988-1990 negotiated A&S prices were less than U.S. Southwest alternatives, they were higher than Alberta alternatives.

128. El Paso take-or-pay volumetric charges are appropriately considered as part of the competitive burner-tip price of U.S. Southwest gas.

129. PG&E properly included the El Paso take-or-pay volumetric charge in the price comparison for purposes of Canadian pricing under netback arrangements insofar as U.S. Southwest prices are relevant to Canadian pricing.

130. There were substantial economic rents associated with access to PGT capacity during the record periods as a result of the disparity between Alberta and California market prices and the limited supply of low cost pipeline capacity.

131. By TURN's calculation, PG&E's prices negotiated for A&S gas assigned approximately 90% of the economic rents associated with PGT capacity to A&S producers.

132. The disallowance proposed by DRA and TURN assumes that PG&E and the A&S pool had negotiated prices which assigned the economic rents on PGT in a 50/50 fashion, based upon Alberta domestic spot gas as a proxy of the Alberta market.

133. The disallowance proposed by SMUD assumes that the UEG and noncore customers could have procured gas at Alberta one-year firm direct spot gas prices respectively outside of the core portfolio while the remaining A&S purchases could have been priced based upon a 50/50 sharing of rents, based upon the Western Gas Marketing Limited (WGML) aggregator price as a proxy of the Alberta market.

134. The 1989 price negotiation resulted in a Tier I commodity cost of $1.90/MMBtu commodity cost at the Canadian-U.S. border for long-term Alberta gas for a term of 15 months.

135. During the time PG&E's long-term Canadian gas was priced at $1.90 for Tier I volumes, Southwest spot gas was priced as high as $3.18/MMBtu, while Alberta spot gas was priced as low as $1.02/MMBtu.

136. In the 1989 price negotiation, PG&E characterized its offered $1.90/MMBtu price as "the highest price PG&E's market can absorb while keeping the core portfolio attractive for core election."

137. In D.90-07-065, the Commission recognized that PG&E's core election of its UEG load had dampened competition in ways which were costly to all ratepayers and accordingly significantly modified the prospect of using core election and UEG participation as a leveraging strategy in core gas procurement.

138. By the 1990 record period the increased reliability of Southwest spot deliveries, price moderation for spot supplies, and a greater willingness on the part of producers in the U.S.

Southwest to enter into long-term contracts indicated an improved environment in which to bargain aggressively for prices based on intra-Alberta competition.

139. PG&E's revised 1990 gas purchase policy reflected some willingness to supplant long-term supplies with short-term or spot gas, increasing the competition between those supplies by lowering the competitive threshold, and emphasizing intraregional supply diversity and price competition.

140. While PG&E's revised 1990 gas purchase policy was generally consistent with the Commission's changed objectives, PG&E's 1990 renegotiation of A&S prices still failed to achieve a price based on intra-Alberta market influences.

141. The tactics used in the 1990 Canadian supply price negotiation consisted of a combination of an attempt to introduce intraregional price competition into the Tier II gas segment combined with the threat to use one-on-one price negotiations, if the intraregional pricing effort proved unsuccessful.

142. Although PG&E's tactics in the 1990 price renegotiations were a step in the right direction, PG&E could have achieved greater success had it started earlier to move toward a more competitive market environment.

143. The Canadian federal and provincial reaction to A&S/PG&E's 1990 price negotiation strategy could have been different had PG&E positioned itself earlier to set the stage for a more competitive environment among Alberta producers.

144. In the 1990 price negotiation, PG&E attempted to implement intraregional pricing for tier II or impose one-on-one negotiations as an alternative.

145. The 1990 price renegotiation resulted in an Alberta gas price of $0.24/MMBtu lower than U.S. Southwest gas on an average cost basis, but $0.51 per MMBtu higher than average U.S. spot exports from Alberta.

146. The record evidence supports the conclusion that at least 300 MMcf/d of PG&E's Canadian gas supply, obtained through the A&S pool, could have been obtained at a lower overall cost from alternative supplies within Alberta compared with PG&E's recorded costs.

147. PG&E had a procurement obligation both to its captive core and core-elect customers through a common supply portfolio.

148. The synergistic benefits of core election enhanced PG&E's opportunity to diversify the core portfolio with short-term supplies.

149. Tariff rules applicable to curtailment priorities were a factor PG&E should have considered in doing core procurement planning.

150. DRA has asserted that PG&E had three basic alternative Canadian gas procurement options which would have possibly resulted in lower Canadian gas costs to PG&E's California customers.

151. The procurement alternatives postulated by DRA are: (1) acquire gas from existing sources (i.e., A&S producers) at lower costs through harder negotiation; (2) acquire gas from alternative Alberta sources (non-A&S producers), either through A&S or PGT, or by PG&E direct purchase; or (3) reduce usage of PGT capacity, convert to transport status and stand aside, and allow alternative noncore purchasers to acquire Alberta gas.

152. Any Canadian gas procurement option available to PG&E which would have lowered gas costs for noncore customers but which would have increased gas costs for PG&E's core customers, including its UEG and core-elect customers, would have been imprudent for PG&E to pursue.

153. A determination of the feasibility of any potential alternatives to PG&E's existing PGT/A&S Canadian gas supply arrangement during each of the three record periods requires an examination of the market and regulatory factors crucial to the viability of those alternatives.

154. In order for PG&E purchase of alternative Alberta sources of short-term gas to be feasible, the following conditions must all be satisfied:

a. Alberta producers must be willing to sell gas to PG&E's market at a price below the A&S price;

b. Requisite volumes of Alberta spot gas available for sale into PG&E's market must exist;

c. Reliable and available transport on NOVA must exist;

d. Reliable and available transport on ANG must exist;

e. A removal permit from Alberta must be obtained; and

f. An export license from the NEB must be acquired.

155. Based on the record, it is reasonable to conclude that these conditions could have been satisfied during the record periods for volumes in excess of 700 MMcf/d of incremental gas load.

156. Since PG&E failed to seriously seek alternative supplies within Alberta, there is no evidence that the Canadian government actually denied PG&E access to such supplies during the record periods.

157. PG&E's gas pricing model indicates that Alberta producers seek to segment their end-use markets and systematically differentiate by market, based on at least two variables: the cost of transportation and the price of competing energy sources in the buyer's market.

158. PG&E's evidence also shows, however, that Alberta producers cannot completely control prices among end-use markets and that statistically only about 50% of Alberta spot export prices can be explained by buyer-specific end-use alternatives.

159. By indicating that only about 50% of Alberta spot price exports are correlated with end-users competing alternatives, PG&E's price model lends support to the finding that PG&E's bargaining power would have been roughly matched evenly against that of Alberta producers in negotiating for incremental short term volumes outside of the A&S pool.

160. Based upon roughly even bargaining power, a reasonable negotiated outcome would be a gas price approximately half way between the buyer's and the seller's marginal opportunity cost.

161. A theoretically correct measure of Alberta producers' marginal opportunity cost, representing a floor value of a negotiating range, would be the point of indifference between selling gas versus shutting in the supplies as being uneconomic.

162. The NEB Alberta export spot price represents a reasonable proxy of a floor value in that it represents the market value at which producers still found it economical to consummate spot sales outside of Alberta.

163. Reasonableness reviews for subsequent periods may develop more refined estimates of Alberta producers' shut-in values applicable to those record periods for purposes of evaluating PG&E's bargaining performance with Canadian suppliers.

164. A market price based on equal weighting of the floor and ceiling values identified above approximates the price which PG&E could reasonably have achieved for Canadian volumes above 700 MMcf/d over the record periods.

165. Based upon application of an equal weighting of buyer and seller floor and ceiling values as outlined above, the resulting prices would be those set forth in Appendix B.

166. If PG&E reduced its purchases from the A&S producer pool, it is highly unlikely that A&S producers would be able to increase the unit price offered to compensate for the loss of load factor benefits.

167. If PG&E had reduced its takes under the A&S pool to the 50% minimum take level, the A&S pool would have suffered a substantial loss of core-elect load being served.

168. PG&E acted reasonably with respect to the 1984 negotiations which led to PGT's reduced outstanding take-or-pay liability under the International Contract.

169. If PG&E reduced its takes under the A&S pool by volumes of 300 MMcf/d on average, it could both assure core peak load reliability, and retain some leverage by offering the A&S pool some remaining core-elect load.

170. The load factor benefits provided to the A&S pool by serving PG&E's core-elect load were proportional to the load served.

171. Based upon a reduction in A&S pool purchases by an average of 300 MMcf/d over the record periods, the A&S price would likely have remain unchanged.

172. In negotiating with the A&S pool, PG&E would be reasonable to offer a price which took into account both the ability of the pool to bargain for U.S. Southwest-benchmarked prices on volumes up to 700 MMcf/d and the ability of PG&E to bargain for Alberta-benchmarked prices on incremental volumes for which it had alternatives outside of the A&S pool.

173. Based upon this principle, the net savings which PG&E could reasonably have factored into its negotiations with A&S producers during the record periods are as set forth in Appendix B.

174. In postulating that PG&E could obtain sufficient volumes of spot gas at intra-Alberta prices, DRA did no analysis of the volumes of Alberta spot gas it alleged that was available for sale to California.

175. During the record periods, intra-Alberta spot sales did not supply substantial volumes of gas.

176. Given the large surplus deliverability generally for Canadian gas through the record period, it would only require a

very small percentage of the plentiful Canadian reserves to satisfy a portion of PG&E's incremental short term Canadian gas demand, had PG&E sought it out.

177. PG&E's sources of short term Canadian gas were not limited merely to recorded spot sales, but could also have included additional reserves which were potentially available, but not sold because they were crowded out by full use of NOVA and ANG capacity by the A&S pool.

178. Evidence of the pent up supply of Alberta gas which could have been sold to PG&E but for the full transport capacity utilization by the A&S pool can be found in the PGT Section 311 lottery queue which was subscribed up to 12 bcf/d.

179. The January 1991 FERC PGT Expansion decision's recognition of (1) PGT's estimate of 70 Tcf of established Canadian natural gas reserves, and (2) PGT's estimates of annual surplus deliverability averaging 1 Tcf per year beginning in 1988, undermines the credibility of PG&E's argument that an imminent shortage of Canadian natural gas supplies loomed during the record period.

180. PG&E has presented no evidence that any portion of the 12 Bcf/d (12,000 MMcf/d) of gas supplies waiting in its Section 311 interruptible shipper queue could not be physically transported into the NOVA system.

181. DRA's "open access" strategy would have required PG&E to convert a portion of its firm sales rights on PGT.

182. Conversion of a portion of PG&E's firm sales rights to firm transport rights would have been consistent with Commission directives during the record periods and would have increased PG&E's bargaining leverage.

183. Given PG&E's 100% ownership of PGT and its priority status as an LDC holder of firm sales rights on PGT, PG&E could have effectively protected itself against risks of pregranted abandonment and loss of capacity rights on PGT.

184. Given the extraordinarily high demand for gas in California during the record periods, the Commission warned all California public utilities against taking actions that might have compromised the utilities' access to interstate pipelines.

185. While there were third-party transportation options available on PGT throughout the record periods, high core election precluded opportunities for significant volumes of noncore sales.

186. If Alberta producers or marketers held firm rights on the NOVA and/or ANG pipelines, they would have likely been able to sell gas directly to the noncore California market at prices at or above the long-term commodity price paid by PG&E given the manner in which the Section 311 queue rationed PGT capacity.

187. No Canadian spot market comparable to the U.S. spot market existed during the first two record periods; such a market began to develop during the third period.

188. If noncore customers had purchased Alberta gas independently outside of the core portfolio, the core WACOG would have increased for remaining core customers to the extent the percentage of Alberta gas assigned to the core portfolio would have declined relative to more expensive alternatives.

189. PG&E's UEG did not have the option to directly procure gas; any procurement strategy during the record periods based on UEG direct procurement would have violated CPUC policy.

190. Disallowances for allegedly imprudent purchases of gas supplies must be calculated based on prices derived from actual measured opportunity costs of options demonstrated feasible and available supplies that meet the Commission's procurement criteria.

191. DRA has not adequately justified the validity of the specific pricing assumptions it has advanced as a basis for any disallowance.

192. The intra-Alberta spot price upon which DRA bases its displacement recommendations applies only to buyers within Alberta.

193. Even assuming the availability of intra-Alberta short-term gas for export, the equitable field price for exported short-term gas at major import points is substantially higher than the intra-Alberta field-direct price used by DRA.

194. The DRA's recommended disallowance is derived from a calculation based on the acquisition of approximately 500 MMcf/d of Alberta spot gas at a hypothetical price that no buyer outside of Alberta could likely obtain.

195. DRA's $392 million disallowance is not related to any single procurement strategy and is not supported by adequate overall analysis.

196. DRA's $392 million disallowance fails to consider the full effect on core ratepayers by holding all other supply and pricing factors constant.

197. SMUD's alternative procurement strategies are designed to benefit UEG and noncore, and likely would have imposed higher costs on core customers.

198. To the extent SMUD's alternative procurement strategy would benefit noncore and UEG interests ahead of the core, it is inconsistent with the Commission's procurement objectives.

Conclusions of Law

1. It is within the scope of our jurisdiction to review the reasonableness of all alternative options available to PG&E with respect to its procurement of Canadian gas supplies. These options include bargaining more effectively with the A&S producer pool.

2. PG&E's purchase policies and procurement practices conducted with respect to its purchases of Canadian source gas during the three record periods beginning February 1, 1988 and

ending December 31, 1990 were reasonable in light of the events and circumstances then applicable, except as specifically noted below.

3. PG&E has not shown that there were impediments which would have foreclosed any opportunity by PG&E to purchase more competitively priced gas, either from the A&S pool or alternative Alberta producers.

4. PG&E was imprudent to the extent it failed to take reasonable steps to bargain more aggressively with the A&S producer pool for prices which recognized competitive market forces within Alberta.

5. PG&E was not legally precluded by contractual supply obligations from reducing its purchases through the A&S pool by up to 50% of licensed volumes assuming prices were not offered on a competitive basis.

6. No official CPUC pronouncement other than this decision has judged the reasonableness of PG&E's Canadian gas purchases or related management actions during the 1988-90 record periods.

7. While various CPUC decisions and rulemakings provided broad guidelines and goals regarding PG&E's operations under new restructuring rules, no official CPUC pronouncement dictated the specific manner in which PG&E was to manage its procurement of Canadian gas.

8. The disallowances proposed by DRA, TURN, and SMUD overstate the amount of imprudent costs which were incurred by PG&E during the record periods, and should be rejected to that extent.

9. PG&E could have reduced its Canadian gas costs by $90,133,000 within compliance of all state, federal, and Canadian laws and regulations.

10. There is no basis to conclude that the Canadian government would have unilaterally confiscated the NOVA/ANG transport rights held by A&S to the extent those transport rights were used to import short-term gas of 300 MMcf/d, and assuming the

A&S pool refused to match the competitive price of such short term gas.

11. While the Canadian government exercises authority over export licenses and removal permits for sales of Canadian gas to U.S. customers, there is no basis to conclude that Canadian authorities would have prohibited PG&E from purchasing gas at more competitively priced levels from the A&S pool, assuming a freely negotiated agreement with the A&S pool.

12. Assuming the A&S pool refused to offer an overall price to PG&E for full contract volumes which considered competitive market forces within Alberta, there is no basis to conclude that Canadian authorities would have prohibited PG&E from purchasing gas within Canada from a combination of (1) the A&S pool for volumes up to 700 MMcf/d and (2) independent Alberta producers for residual requirements above 700 MMcf/d up to the full PGT pipeline capacity, at prices and terms as assumed above.

13. PG&E should be authorized recovery of its Canadian gas costs incurred during the record period, except for those costs found to be imprudent as noted below.

14. Canadian gas costs in the amount of $90,133,000 plus accrued interest beginning on April 1, 1988 should be found to be imprudently incurred and disallowed from recovery since PG&E has not meet its burden of proof with respect to the reasonableness of such costs.

15. This decision defers any conclusion concerning the amount, if any, of imprudent Canadian costs passed through as Northwest power purchases, or as prices paid to QFs or geothermal suppliers.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E) is denied recovery of $90,133,000 plus interest in Canadian gas costs incurred during the period April 1, 1988 through December 31, 1990 on the basis of imprudence.

2. Adjustments in revenue requirement, revenue allocation, rate design, and appropriate accounting entries associated with this disallowance shall be considered in PG&E's next scheduled Biennial Cost Allocation Proceeding.

This order is effective today.

Dated March 16, 1994, at San Francisco, California.

DANIEL Wm. FESSLER
President
P. GREGORY CONLON
JESSIE J. KNIGHT, JR.
Commissioners

I will file a written dissent.
/s/ NORMAN D. SHUMWAY
Commissioner

Commissioner Patricia M. Eckert is absent.

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List of Appearances

Applicant: Steven Burke, Roger Peters, Michael Reidenbach, Edward V. Kurz, Mark Huffman, Cheryl White Mason, Michelle L. Wilson, Terry J. Houlihan, and Robert McLennan, Attorneys at Law, and Harry W. Long, Jr., for Pacific Gas and Electric Company.

Interested Parties: Roger Berliner, Attorney at Law, for Alberta Petroleum Marketing Commission; Beth Bowman and Keith Melville, Attorneys at Law, for San Diego Gas & Electric Company; Wright and Talisman, by Michael Day and Jerome Candelaria, for ERON; Greg Giesbrecht, for Pan-Alberta Gas Ltd.; John W. Jimison and Dennis Prince, for Independent Petroleum Association of Canada; Robert A. Jones, Attorney at Law, for Gene Satrap; Martin A. Mattes, D. Marchant, and Melissa S. Waksman, Attorneys at Law, for Kern River Gas Transmission Company; Patrick J. Power, Attorney at Law, for Sacramento Municipal Utility District; Gene Satrap, for Texas-Ohio West, Inc.; Daron J. Thomas, for Consolidated Fiberglass Products Company; C. Hayden Ames, Attorney at Law, for Chickering & Gregory; Barkovich and Yap, by Barbara Barkovich, for Barkovich and Yap; Patrick J. Bittner and Caryn Hough, Attorneys at Law, for California Energy Commission; Morrison & Foerster, by Jerry Bloom and Lynn Haug, Attorneys at Law, and Morse, Richard, Weisenmiller & Associates, by Mark Younger, for California Cogeneration Council; Jackson, Tufts, Cole & Black, by William H. Booth and Joseph S. Faber, Attorneys at Law, for California Large Energy Consumers Association; Henwood Energy Services, by David Branchcomb, for Independent Energy Producers Association; Maurice Brubaker, for Drazen Brubaker & Associates; McCraken, Byers & Martin, by David J. Byers, Attorney at Law, for Peninsula Street Light Authority and City of Fresno; Ralph Cavanagh, Attorney at Law, for Natural Resources Defense Council; Brobeck, Phleger & Harrison, by Gordon E. Davis, Attorney at Law, for California Manufacturers Association; Sam De Frawi, for Naval Facilities Engineering Comm.; Phil DiVirgilio and Greg Blue, for Destec Energy, Inc.; Karen Edson, for KKE & Associates; Norman Furuta, Attorney at Law, for Federal Executive Agencies; Steven A. Geringer, Attorney at Law, for California Farm Bureau Federation; Grueneich, Ellison & Schneider, by Dian M. Grueneich, Attorney at Law, for California Department of General Services; Steve Harris, for Transwestern Pipeline Company; Fulbright & Jaworsky, by Pat Keeley, Attorney at Law, and Recon Research Corporation, by Dr. Andrew Safir, for Canadian Petroleum Association; Roberts & Kerner, by Douglas K. Kerner,

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Attorney at Law, for Geothermal Resources Association; Joseph G. Meyer, for Joseph Meyer Associates; Melissa Metzler and Andrew Brown, for Barakat & Chamberlin; Steven Moss, for Spectrum Economics, Inc.; Anderson, Donovan & Poole, by Edward G. Poole, Attorney at Law, for various clients; John D. Quinley, for Cogeneration Service Bureau; Florence J. Pinigis, Bruce A. Reed, Janet K. Lohmann, and David R. Hinman, Attorneys at Law; for Southern California Edison Company; C. B. Rooney and David J. Gilmore, Attorneys at Law, for Southern California Gas Company; Donald Salow, for Association of California Water Agencies; Bartle Wells Associates, by Reed V. Schmidt, for California City-County Street Light Association; Michel P. Florio and K. Justin Reidhead, Attorneys at Law, for Toward Utility Rate Normalization; Downey, Brand, Seymour & Rohwer, by Phil Stohr and Ron Liebert, Attorneys at Law, for Industrial Users; Randolph L. Wu, Phillip D. Endom, and Kenneth L. Wiseman, Attorneys at Law, for El Paso Natural Gas Company; Larry Goldberg, for Sequoia Technical Services; Carolyn Kehrein, for Procter & Gamble Manufacturing Company; Sara Steck Myers, Attorney at Law, for Coalition for Energy Efficiency and Renewable Technologies; Thomas A. Tribble, P.E, J.D., for Regents - University of California; Messrs. Ater, Wynne, Hewitt, Dodson & Skerritt, by Mark Trinchero, Attorney at Law, for Cogenerators of Southern California; William B. Marcus, for JBS Energy, Inc., and Philip J. DiVirgilio for Agrico Cogeneration Corporation.

State Service: Messrs. Greve, Clifford, Diepenbrock & Paras, by Matthew V. Brady, for California Department of General Services.

Commission Advisory and Compliance Division: Martha J. Sullivan.

Division of Ratepayer Advocates: Diana L. Lee, Hallie Yacknin, James E. Scarff, and Robert Cagen, Attorneys at Law, and Sandra Fukutome, William Gibson, Natalie Walsh, and Jeff Meloche.

Division of Strategic Planning: Jeffrey Dasovich.

(END OF APPENDIX A)

APPENDIX B

Disallowance Calculation
(April 1, 1988 thru December 31, 1990)

I. Imputed Gross Savings on Alternative Purchases over 700 MMcfd.

	Annual Canadian Purchases (MMcf)	Daily Canadian Purchases (MMcfd)	Purchases Above 700 MMcfd	Ceiling A&S Price ($/Dth)	Floor Spot Price ($/Dth)	Imputed Market Price ($/Dth)	Imputed Unit Savings ($/Dth)	Annual Amount Saved (M$)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1988	269,858	981	281	1.72	1.18	1.45	0.27	21,317
1989	371,137	1,017	317	1.81	1.14	1.48	0.34	39,457
1990	370,042	1,014	314	1.83	1.32	1.57	0.25	29,358
1988-1990 Total								90,133

Notes: Annual Savings (H) equals (C) * [# of days] * [heat rate] * (G). The heat rate is derived from PG&E's workpapers (Exhibits 1009, 1010) and is approximately 1.013 MDth/MMcf. The imputed "PG&E Market Price" (PMP) equals 0.5*(D) + 0.5*(E). The annual prices in (D) are based on monthly data from DRA's workpapers, Exhibit 1101, as supplemented by Exhibits 1406, 1687, 1723, and 1724. The monthly prices are weighted by monthly purchases in excess of 700 MMcfd.
The prices in (E) are taken from Exhibit 1026.

II. Interest and Total Disallowance thru December 1993.

	Annual Amount Saved (M$)	Compound Interest Factor	Annual Interest (M$)	Total Amount Disallowed (M$)
	(A)	(B)	(C)	(D)
1988	21,317	1.39480	8,416	29,733
1989	39,457	1.29191	11,518	50,975
1990	29,358	1.18721	5,496	34,855
Totals	90,133		25,430	115,563

Notes: Annual Amount Saved (A) from I.(H) above. Interest (C) equals (A) * ((B)-1). Compound interest factors, based on 3-month commercial paper rates compounded monthly through December 1993, are shown in Appendix C.

(END OF APPENDIX B)

APPENDIX C

Interest Rates and Compound Interest Factors

I. 3-Month Commercial Paper Rates (April 1988 thru December 1993).

	1988	1989	1990	1991	1992	1993
January		9.04%	8.10%	7.10%	4.07%	3.25%
February		9.37%	8.14%	6.49%	4.11%	3.18%
March		9.95%	8.28%	6.41%	4.30%	3.17%
April	6.86%	9.81%	8.30%	6.07%	4.04%	3.14%
May	7.19%	9.47%	8.25%	5.92%	3.88%	3.14%
June	7.49%	9.11%	8.14%	6.11%	3.92%	3.25%
July	7.82%	8.68%	7.99%	6.05%	3.44%	3.20%
August	8.26%	8.57%	7.88%	5.72%	3.38%	3.18%
September	8.17%	8.70%	7.96%	5.57%	3.24%	3.16%
October	8.24%	8.53%	7.98%	5.35%	3.33%	3.26%
November	8.66%	8.35%	7.91%	4.98%	3.66%	3.40%
December	9.11%	8.29%	7.80%	4.61%	3.67%	3.36%

Source: Federal Reserve Board, San Francisco, California.

II. Compound Interest Factors for Record Period (April 1988 thru December 1990).

	1988	1989	1990
January		1.34726	1.23185
February		1.33719	1.22359
March		1.32683	1.21535
April	1.43005	1.31591	1.20702
May	1.42192	1.30524	1.19873
June	1.41345	1.29502	1.19054
July	1.40468	1.28527	1.18252
August	1.39559	1.27604	1.17470
September	1.38605	1.26699	1.16704
October	1.37667	1.25787	1.15934
November	1.36728	1.24899	1.15169
December	1.35749	1.24036	1.14414
Mean	1.39480	1.29191	1.18721

Notes: Interest compounded monthly at one-twelfth of annualized monthly rate.
Mean values used to calculate interest on disallowance (Appendix B, Part II(C)).

(END OF APPENDIX C)

APPENDIX D

Canadian Gas Prices
Under Adopted Alternative Procurement Strategy

	A&S Pool Purchases		Independent Alberta Producer Purchases		Aggregate Alberta Purchases		Recorded A&S Price	Indep: % Discount from Recorded A&S Price	Aggregate: % Discount from Recorded A&S Price
	Volume (MMcfd)	Price ($/Dth)	Volume (MMcfd)	Price ($/Dth)	Volume (MMcfd)	Price ($/Dth)	($/Dth)		
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1988	700	1.72	281	1.45	981	1.65	1.72	15.78%	4.52%
1989	700	1.81	317	1.48	1,017	1.71	1.81	18.58%	5.79%
1990	700	1.83	314	1.57	1,014	1.75	1.83	13.86%	4.29%

Notes: The data in Columns (C), (D), (E), and (G) above are extracted from Appendix B, Part I, Columns (C), (F), (B), and (D), respectively.
Column (H) shows the percentage price reduction from recorded A&S prices for independent purchases.
Column (I) gives the corresponding percentage for aggregate purchases.

(END OF APPENDIX D)

APPENDIX E

Canadian Price Comparison
($ per Dth)

	A&S	Other Aggregators: WGML	Other Aggregators: ProGas	Other Aggregators: Pan-Alberta	CNGF Intra-Alberta Spot	PG&E Intra-Alberta Spot	NEB Ex-Alberta Spot	AMP	80% of AMP
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1988	1.73	1.37	1.22	1.21	0.98	0.97	1.18	1.33	1.06
1989	1.82	1.33	1.40	1.22	1.08	1.10	1.14	1.36	1.09
1990	1.83	1.39	1.46	1.25	1.02	1.02	1.32	1.40	1.12

Source: Columns (A) thru (E), (H), and (I) based on Exhibits 1100, 1101, 1406, 1687, 1723, 1724. Column (F) based on Exhibits 1042 and 1050; Column (G) based on Exhibit 1026.

Notes: Prices are simple unweighted means. 1988 means based on April thru December, except for Column (G), which are annual figures.

(END OF APPENDIX E)

APPENDIX F

Southwest Average Cost Comparison
With Equivalent Canadian Commodity Rate
(Prices and Costs in $/Dth)

Line		1988	1989	1990
1	Commodity Rate Analysis (CRA) Load Factor	70%	70%	75%
2	Southwest Load Factor	77%	91%	92%
3	A&S Pool Load Factor Under Alternative Purchase Scenario	70%	70%	70%
4	Southwest Unit Fixed Costs @ CRA Load Factor	0.30	0.27	0.22
5	Southwest Unit Fixed Costs @ Southwest Load Factor	0.27	0.21	0.18
6	Canadian/PGT Unit Fixed Costs @ CRA Load Factor	0.48	0.50	0.59
7	Canadian/PGT Unit Fixed Costs @ A&S Pool Load Factor	0.48	0.50	0.63
8	Expected Southwest Commodity Cost at California Border	2.01	2.20	2.33
9	Expected Southwest Delivered Cost @ Southwest Load Factor	2.28	2.41	2.51
10	Equivalent Canadian Commodity Cost @ A&S Pool Load Factor	1.80	1.91	1.88
11	Actual PGT Commodity Rate (weighted mean)	1.83	1.91	1.99
12	PGT Savings vis-a-vis Equivalent Canadian Commodity Rate	-0.02	-0.00	-0.11

Notes:

Lines 1,4,6,8 from PG&E's Commodity Rate Analyses (Exhibits 1022-1024, Pages 45,71,89). Line 8 uses average 1988 commodity cost from Page 45 of Exhibit 1022. Canadian/PGT unit fixed costs on Line 6 include downward adjustment to reflect pro rata allocation of PGT fixed costs between its sales service and the prudent alternative transportation service.

Line 2 calculated from Southwest throughput in PG&E's Workpapers (Exhibit 1010, Page 2).

Line 5 = Line 4 * (Line 1/Line 2).

Line 7 = Line 6 * (Line 1/Line 3).

Line 9 = Line 8 + Line 5.

Line 10 = Line 9 - Line 7.

Line 11 calculated from monthly PGT commodity rates, weighted by monthly volumes, in PG&E's workpapers (Exhibit 1010, Pages 4-5).

Line 12 = Line 10 - Line 11.

(END OF APPENDIX F)

APPENDIX G

Glossary

ACAP	Annual Cost Allocation Proceeding
AMP	Average Market Price (Alberta)
ANG	Alberta Natural Gas Company
A&S	Alberta and Southern Gas Company
APMC	Alberta Petroleum Marketing Commission
Bcf	Billion Cubic Feet
Btu	British Thermal Unit
CEC	California Energy Commission
CFR	Code of Federal Regulations
CGPA	California Gas Policy Act
CNGF	Canadian Natural Gas Focus
COS	Cost of Service
CPA	Canadian Petroleum Association
CPCN	Certificate of Public Convenience and Necessity
CPG	Canadian Producer Group
CPUC	California Public Utilities Commission
DCQ	Daily Contract Quantity
DOE	United States Department of Energy
DRA	Division of Ratepayer Advocates
Dth	Decatherm (equals one MMBtu)
ECAC	Energy Cost Adjustment Clause
El Paso	El Paso Natural Gas Company

APPENDIX G (Continued)

EM&R	Department of Energy, Mines and Resources (Canada)
ERA	Economic Regulatory Administration (United States DOE)
ERCB	Energy Resources Conservation Board (Alberta)
FERC	Federal Energy Regulatory Commission
GRC	General Rate Case
GRPA	Gas Resources Preservation Act (Alberta)
IPAC	Independent Petroleum Association of Canada
LDC	Local Distribution Company
MMBtu	Million British Thermal Units (equals one Dth)
MMcf	Million Cubic Feet
MMcf/d	Million Cubic Feet Per Day (also MMcfd)
MFV	Modified Fixed-Variable
NEB	National Energy Board (Canada)
NGA	Natural Gas Act (United States)
NGMA	Natural Gas Marketing Act (Alberta)
NGPA	Natural Gas Policy Act (United States)
NOPR	Noticed of Proposed Rulemaking
NOVA	NOVA Corporation of Alberta
PGA	Purchased Gas Account
PG&E	Pacific Gas & Electric Company
PGT	Pacific Gas Transmission Company
PIRA	Petroleum Industry Research Associates
RLI	Reserve Life Index
Section 7(c)	Natural Gas Act, Section 7(c)

APPENDIX G (Continued)

Section 311	Natural Gas Policy Act, Section 311
SFV	Straight Fixed-Variable
SMUD	Sacramento Municipal Utility District
TCF	Trillion Cubic Feet
TNV	Transaction Netback Value
TOP	Take-or-Pay
TURN	Toward Utility Rate Normalization
UEG	Utility Electric Generation
WACOG	Weighted Average Cost of Gas
WGML	Western Gas Marketing Limited

(END OF APPENDIX G)

A.91-04-003
D.94-03-050

Norman D. Shumway, Commissioner, Dissenting:

I respectfully dissent from the majority's decision. It is apparent to me that the decision is based upon the application of hindsight analysis. The gaze of reasonableness reviews is intended to focus on whether, given the information known at the time, a utility's decisions were reasonable. There is ample evidence that reveals PG&E's actions were indeed reasonable.

The majority opinion postulates that PG&E could have purchased cheaper Canadian gas through either replacing A&S pool gas with Canadian spot gas for incremental volumes or used alternative Canadian supplies as leverage to bargain with A&S producers for lower prices. In my opinion, the evidentiary record reveals that regulatory and market conditions during the record period from 1988 to 1990 did not support the feasibility of such strategies.

PG&E was bound by the dictates of this Commission to secure reliable gas supplies at reasonably low cost for its core customers. Given the circumstances, PG&E satisfactorily achieved these objectives. I believe it unlikely that had the utility pursued the alternatives put forth in the decision, it could have better achieved these objectives. As pointed out in the decision and by other parties of record, the price paid for Canadian gas supply was significantly cheaper than any domestic gas supply. I believe that the price disparity between Canadian gas and southwest gas should not be underemphasized.

Could PG&E have negotiated more aggressively with A&S? The record reflects that PG&E unsuccessfully attempted to bring intra-Alberta spot prices into the negotiations with A&S producers. It was widely perceived that the alternatives available in PG&E's market were limited to the prices of El Paso gas, fuel oil, California gas supply, long-term supply in the U.S. and U.S. spot supply. The price of intra-Alberta gas was an irrelevant consideration under the International Contract between PGT and A&S.

Furthermore, both the Canadian and Alberta governments enforced policies that prevented the export of spot gas. It is extremely doubtful that the Alberta government or Canada's National Energy Board would have allowed alternative gas supplies to displace supplies under the International Contract.

The decision posits that PG&E did not use its core-elect market as an effective bargaining chip to stimulate competition among Canadian producers when negotiating with A&S producers. However, considering the unwillingness of the A&S producers to include competitive Canadian prices in negotiations, it is evident that such a strategy would have been unrealistic. It should be noted that PG&E did make use of the core-elect option and its UEG market to the extent it was effective to do so in order to negotiate favorable terms. Other parties and the decision to some degree contend that PG&E was motivated to keep the PGT pipeline filled with A&S pool gas and, therefore, had little incentive to use the core-elect as a bargaining tool in order to extract further price concessions. The lack of evidence supporting this conclusion reduces this argument to mere speculation.

How could PG&E have purchased gas that was neither adequate in volume nor possible to transport? The position that PG&E could have procured the cheaper Alberta spot supplies is questionable since the volume of these supplies was very limited on an immediate basis. Had PG&E used this alternative, it would have surely sacrificed reliability.

The decision surmises that A&S could have used its existing capacity rights on the NOVA pipeline to transport non-A&S supplies. The fact that A&S's receipt capacity on the NOVA system was limited to specific locations and was not transferable to locations where non-A&S producers may have been located is obscured. Moreover, the record reveals that the Alberta gas reserves presumably available to PG&E were non-producing, shut-in gas reserves and required more than two years to interconnect to the transportation system.

According to the decision, PG&E would have had to (1) jeopardize reliability and price stability of gas supplies to its core and core-elect ratepayers, (2) disregard the clearly unyielding positions of the A&S producers who were supported by the Canadian and Alberta governments, and (3) ignore the mandates and policies of this Commission. Based on evidence which supports the certainty of these risks, I cannot support the finding of unreasonableness contained in the majority opinion.

/s/ Norman D. Shumway
NORMAN D. SHUMWAY
Commissioner

March 16, 1994
San Francisco, California